NS-4

NON-CONVENTIONAL POWER OPTIONS

NUCLEAR GENERATION OPTION

DALCOR, 1981

NON-CONVENTIONAL

POWER OPTIONS

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1.0 INTRODUCTION AND SUMMARY

In this section the following non-conventional power options are reviewed:

- Small Hydro and Run-of-River
- Biomass
- Wind energy
- Geothermal
- Nuclear Fusion
- Hydrogen

Saskatchewan Power Corporation's general order of consideration of these alternatives would place priority on small hydro and run-of-river projects because of the known technology, relative ease of operation and availability of sites. Such projects can supply local area loads and/or tie into the provincial power grid.

The next alternative would be biomass particularly the wood and wood residue direct burning or wood gasification processes. Pulp, paper and sawmill operations have long used mill residues for process heat, space heating and electric power generation. These co-generation schemes have proven economical and reliable to these industries and it is expected that old and new plants alike will continue to operate in this manner.

Two prototype wood gasification operations are currently being evaluated in Saskatchewan and there is reason to suggest that one of these processes known as the downdraft IMBERT type could be economically effective as an alternative to northern remote diesel operations.

The third option receiving significant attention is that of wind power. Saskatchewan's optimum wind regions generally exist in the southern portion of the province. The unreliability and variability of wind energy suggest that the machines are best suited to serve solitary loads such as farmsteads which can be supplemented by the provincial electric grid.

Geothermal electric power production is currently considered impractical for Saskatchewan. However, the majority of the populated areas of Saskatchewan overlie suitable geologic zones for recovery of low heat value geothermal energy. The temperatures of these zones are generally in the order of 30° to 60°C and are therefore suitable only for space heating. The University of Regina has drilled a geothermal producing well and is currently planning to complete the phase 2 portion of the system which requires a disposal injection well, piping, pumps and heat exchangers. The low heat content, high costs of drilling and the high saline, corrosive content of the subsurface waters are the major obstacles to further development. However, it is gratifying that such a potential energy option lies at the feet of Saskatchewan's population.

Hydrogen and nuclear fusion represent near term and long term technological advances respectively. Nuclear fusion is viewed as one of the utlimate answers to energy supply. At the current stage of development fusion is a negative energy source, that is, it consumes more energy than it produces. However, within the next two decades it is expected that new experimental plants will achieve positive energy. The costs of constructing and operating such complex facilities may prove prohibitive, at least for the forseeable future. It generally appears that hydrogen will be constrained to roles other than for primary electric generation. Hydrogen is currently considered as a means of storing energy derived from unreliable and variable sources such as wind machines. Hydrogen fuel produced from such sources can be transported, stored and used as required. The key advantage of utilizing hydrogen is that it can be derived from water and after combustion the waste product is also water which therefore represents one of the most environmentally acceptable forms of energy.

Other than fusion power these non-conventional energy sources do not appear to have the capability of significantly displacing conventional power grid energy sources such as hydroelectric plants, fossil-fuel thermal plants and nuclear plants.

All of these options will generally only become viable as the costs to construct plants and produce energy from the current conventional non-renewable energy sources rise significantly. There appears to be a high degree of certainty that these costs will continue to escalate and Saskatchewan's non-conventional options may well become prudent power supplies at least for some regional loads within the province.

The table below provides a summary of the key observations concerning the present state of development of each option and estimated time-frames for commercialization.

NON-CONVENTIONAL POWER OPTIONS
SUMMARY OBSERVATIONS

	POWER OPTION					
	Small Hydro	Biomass	Wind	Geothermal space heating only)	Fusion	Hydrogen
Estimated Range of Capital Costs ($/kW)	6000-8000	>1500 wood-fired >1000 gasifier	>1500 swecs >5000 large MW	1600-2000	N/A	1500-2000 (Production) 1500-2000 (Utilization)
Operating Cost Factor vs Diesel	<1	1-2	<1	N/A	N/A	<1 (H_2 delivered as liquid fuel)
s Grid	>1	>2	>1	<1	>10	<1
Technical Concerns	.None .Standard Technology	.Handling Feedstock .Ash Handling	.Mechanical Components .Variable Output	.Corrosion .Low Limits of Physical Distribution	.Fractional Power Output to Input .Sophisticated Technology	.Conversion Efficiency .Storage & Handling
Environmental and Safety Concerns	.Stream Changes .Reservoir Flooding	.Emissions .Defores-tation .Thermal Pollution	.Visual Effect .Noise Levels	.None	.Radio-activity .Thermal Pollution	.Combustible .Handling
Environmental Attributes	.Renewable .Clean .Efficient	.Renewable .Low Sulphur Emmissions .Uses Wood Wastes	.Renewable .Clean	.Renewable	.No Possi-bility of Reaction Runaway .Less Thermal Pollution than Conventional	.Renewable .Clean
Techno-logically Available	Immediate	1983-85	1983-85	1982-84	1990 +	1985-1990
Commercially Available	Immediate	1985 +	1983-85	1984-85	2010 +	1990 +

N/A - not applicable

2.0 SMALL HYDRO AND RUN OF RIVER PROJECTS

The definition of "small hydro" projects generally covers projects ranging in capacity from 0.5 to 50 megawatts. Small hydro is synonymous with local or remote site energy supply as opposed to large hydro projects which are a major component of extensive electric power grids.

Hydro-electric power encompasses the harnessing of a flow of water and dropping it down through a power plant. Therefore, siting of such facilities is normally at waterfalls or rapids. Latest estimates of undeveloped hydro-electric power sites in Canada is in the order of 250,000 megawatts of which "small hydro" is a significant portion.

2.1 CURRENT DEVELOPMENTS

In Eastern Canada and the U.S.A., many small hydro plants are being developed at existing dams or in irrigation schemes. In the United States, recent legislation has given major impetus to the development of small hydro plants at existing dams through funding programs and tax incentives.

Since 1977, the United States has witnessed a surge of activity in hydro-electric development. Applications during 1979 and 1980 to develop various hydro sites were recorded which would propose to develop approximately 4,800 megawatts (1979-2200 MW; 1980-2600 MW). Approximately 95% of the capacity defined in the 1980 applications was for plants of a size less than 30 MW. Over the next six to eight years, at least 600 projects in the U.S.A. will be constructed. These projects will conservatively generate an average 28 billion kilowatt hours.

In British Columbia, Alaska and the Yukon, sites are being investigated to serve remote load centers. These plants will generally utilize a moderate to high load and relatively small flows. In most cases, these developments will be "run of river" types utilizing only minor water storage.

Current generation schemes for isolated loads where small hydro is best utilized is in combination with diesel generation to provide economical and constant electric supply.

2.2 ENGINEERING CONSIDERATIONS

Hydro plants are based on a well known, well established and reliable technology. The major engineering features of small hydro developments are:

- Diversion structure (weir or dam) to impound water
- Intake
- Power canal or pipeline
- Penstock
- Powerhouse enclosing a turbine and generator
- Switchyard and transmission line(s).

The majority of the engineering features outlined above are primarily a factor of the topography and stratigraphy of the hydro site location. Technological considerations will generally be considered to lie within the powerhouse complex, namely the turbine-generator equipment.

There are two basic categories of turbines, known as "Impulse" and "Reaction". The Impulse turbine has two well known variants. One is the Pelton which operates at relatively slow speeds and is economic for the relatively small hydro outputs with heads in excess of 100 meters. Turgo turbines are the other Impulse turbine variant, which merit serious consideration for heads in the 60-200 meter range.

The second turbine category, the "Reaction" turbine, also has variants such as the Francis type 'mixed flow', and the Propeller type 'axial flow'. These turbines can be mounted either horizontally or vertically and are usually more economic for capacities exceeding 10 MW. The Francis type is normally employed for heads in the 25 to over 300 meters (which would be considered "large hydro") range whereas the Propeller type can operate in the 3 to 60 meter head range. A recent design concept (Mini-Hydel) undertaken for two small hydro installations in Ontario employs the Francis type turbine for heads in the range of 3 meters to 7.5 meters.

A variant to the "Impulse" turbine is the Banki or cross-flow design. The head range is generally from 5 to 200 meters with outputs up to 1 megawatt as standardized designs.

Few turbines operate satisfactorily at less than 40 percent capacity except for Impulse and cross-flow designs. The efficiency of energy conversion is in the order of 90 percent at rated capacity.

The applications of each type of turbine for various heads and capacities is shown in Figure 1.

The second item of technological equipment is the generator which is available as either synchronous or induction (asynchronous) types. The synchronous has its own excitation system and is therefore the only type suitable for isolated areas. Generator efficiencies are generally 90-98 percent throughout the load range.

2.3 ENVIRONMENTAL CONSIDERATIONS

The benefits of small hydro installations include:

- Hydro energy is renewable
- Generation is clean and combustion-free
- Hydro is an efficient energy producer
- Small hydro will, in general, have more environmental impact than diesel generation; however, the impacts are, as a rule, not major.

Run of river developments normally create the fewest adverse environmental effects, but small hydro usually requires storage and therefore the greatest impact is on the flooded areas. Some of the adverse environmental effects are:

- Impeded upstream or downstream passage of fish
- Changes in reservoir conditions
- Alteration of water temperature, dissolved gas and flow regimes downstream of the dam
- Possible reduction of fish population
- Loss of timber and wildlife habitat in the flooded areas.

2.4 ESTIMATED UNIT COSTS

Hydro plants have higher initial costs than diesel installations, which means that benefits will generally be derived only with a longer pay-out period. However, with the rapid escalation in the price of fossil fuels, many sites are becoming viable. It is also important to recognize that small hydro is virtually inflation-proof and can therefore afford a path towards cost-effective long term future energy security for isolated communities and commercial ventures.

Crippen Consultants of Vancouver, B.C. have prepared a plot of unit energy costs versus capital costs and compared it to unit energy costs from the B.C. Hydro electric grid and to diesel generation (see Figure 2). It is apparent that small hydro sites costing less than $3,100 per kilowatt installed can be considered as viable economic alternatives to diesel, but must be less than $900 per kilowatt installed to be viable against a grid supply. When factors such as load growth, fuel price escalation, diesel replacement costs, etc. are accounted for, then in Crippen's estimation, hydro developments costing up to $5000 per kilowatt installed can be viable against diesel generation. In a case study, Crippen further determined that when hydro-diesel was compared to all-diesel, the after-tax payback period of the higher initial capital investment would be approximately six years.

2.5 REMARKS

Small hydro merits serious consideration as a potentially viable alternative or complementary energy source to diesel generation. Small hydro installations can be tailored directly to the needs and capabilities of clearly defined economic units: towns, mills, mines, factories, etc. They are also aimed at local level operation due to the minimum amount of maintenance required and to the operating features which do not require attendant supervision.

Recent legislation in British Columbia now permits a two year write-off provision for investments in hydro plants of less than 15 MW which provides significant incentive to developers of small hydro sites.

FIGURE 1

TURBINE APPLICATION DIAGRAM 0.5-20 MW RANGE

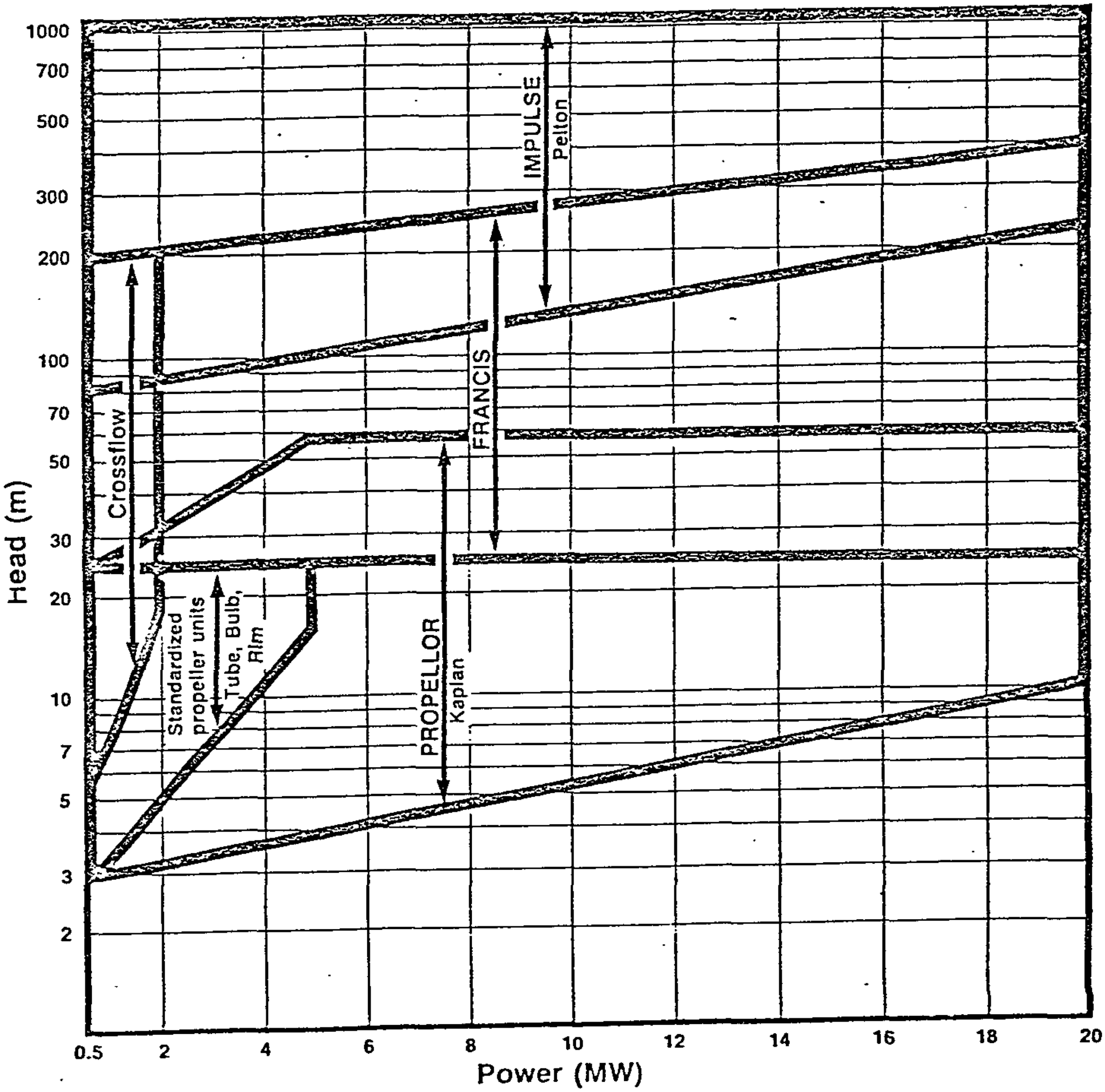
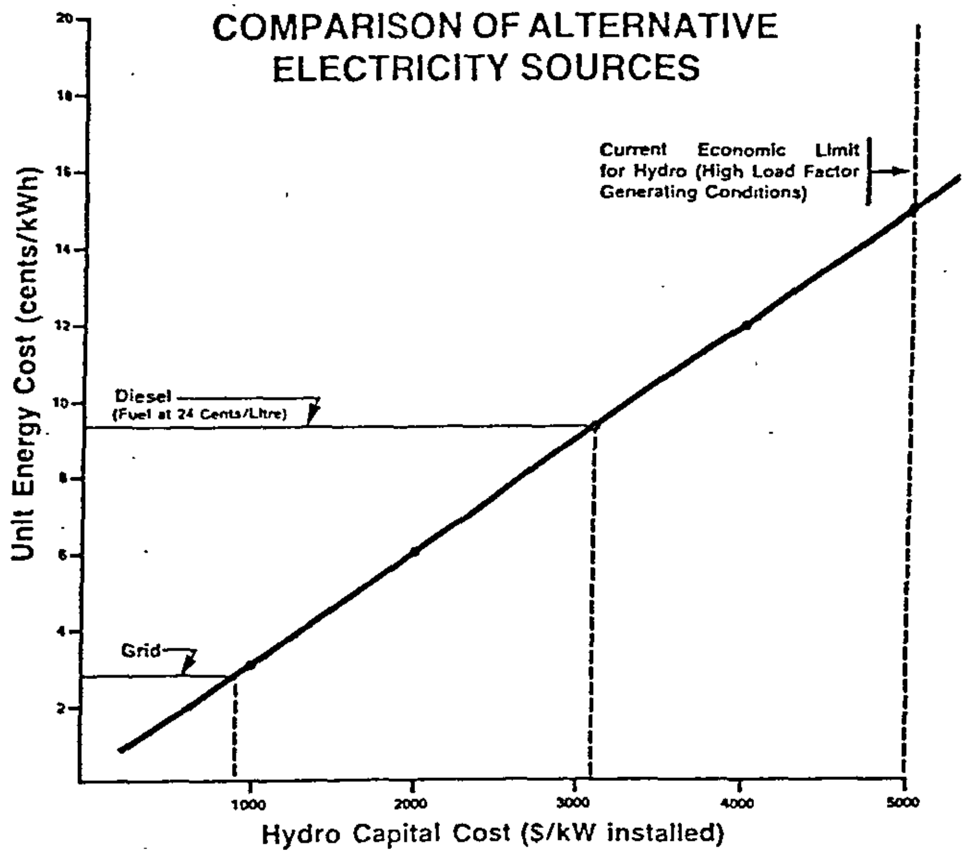


FIGURE 2



COMPARISON OF ALTERNATIVE ELECTRICITY SOURCES
Current Economic Limit for Hydro (High Load Factor Generating Conditions)
Diesel
(Fuel at 24 Cents/Litre)
Grid
Unit Energy Cost (cents/kWh)
Hydro Capital Cost ($/kW installed)
20
18
16
14
12
10
8
6
4
2
1000
2000
3000
4000
5000

3.0 BIOMASS

Energy from biomass refers to the process whereby renewable organic materials are converted to useable forms of energy.

Biomass is recognizable in many forms, for example, wood, pulp, paper and sawmill residues, peat, agricultural waste products, and such exotic forms as marine plants. Biomass is an environmentally attractive fuel yet it is often difficult to collect, store, ship and use.

Conversion processes to produce biomass energy can be direct such as burning or indirect such as by gasification and production of distillates. Gasification yields low to medium heating value gas which can in turn be burned directly or used as fuel for gas turbines, internal combustion engines or in fuel cells to generate electricity.

Distillates are generally considered for use in producing chemicals, man-made fibres, plastics and pharmaceuticals. However, ethanol or methanol can also be produced which are currently attracting interest for use in combination with unleaded gasolines as gasohol or mixed with diesel fuel for subsequent use in internal combustion engines.

Agricultural waste products are less likely to be considered for use in the electric power industry primarily due to the seasonality constraint in the availability of crop residues. However, there is approximately six times the waste residue from crops than from forestry.

The use of peat for energy is common in Europe, particularly in Ireland and Finland. Canada contains substantial peat reserves, however, except for a peat gasifier pilot plant undergoing tests on Prince Edward Island, there is relatively little effort being expended on this alternative. In Saskatchewan, peat reserves are primarily located in the northern regions which are subject to harsh winters. The deep freezing of the peat would make winter harvesting operations difficult and costly.

The direct combustion of wood and mill residues as well as wood gasification are being extensively researched across Canada for application to the production of electric power and will, therefore, be the main subjects for further discussion.

3.1 CURRENT DEVELOPMENTS

Wood and mill residues are the feedstocks most often considered for biomass energy. Direct wood burning is the most visible biomass utilization trend as substantial numbers of North American homeowners have now installed wood burning space heating units thereby displacing oil and electric supply. For Canada, wood stoves and furnaces are in demand and it is expected that this form of energy consumption could eventually represent at least 0.5 percent of total energy use in the country.

3.1.1 Mill Residues

Mill residues have long been converted to energy by pulp and paper plants and sawmills for their direct use in supplying process steam, space heating and electric generation both for in-plant use and often for surrounding communities. Mill residue energy conversion currently accounts for 3.5 percent of Canada's primary energy. Nevertheless, it is believed that mill residues can be used much more extensively and effectively. Forest industries, as well, leave behind a substantial amount of waste materials during logging. If both mill residues and logging waste materials were more effectively used it is rational to suggest that wood could account for up to 7.5 percent of Canada's primary energy.

The Canadian government has recognized this potential by providing grants through their Forest Industry Renewable Energy program whereby grants up to 20% of capital costs for conversion of wood residues to energy would be available.

One of the major obstacles to using wood and wood residues is the handling of the material. In this regard, efforts are being expended towards;

1) improved harvesting methods to economically recover wood logging waste
2) "densifying" the materials into more easily useable pellets, which can then be burned in standard equipment such as industrial boilers.

3.1.2 Wood Gasification

Wood gasification is receiving close scrutiny by many researchers. Recent studies suggest that wood gasification can be competitive with Liquid Petroleum Gas (LPG) or fuel oil for industrial heating.

Two experiments are currently being conducted in Saskatchewan. One gasifier is capable of generating 150 kilowatts using an updraft process requiring wood flake feedstock. The second process is a 60 kilowatt unit downdraft process which effectively uses coarse wood feedstock. The downdraft unit to date appears to be the most efficient and useful of the two units.

Other gasification programs include synergic relationships with natural gas for production of methanol or as a fuel for gas turbine driven compressors. Similarly, wood gas has been suggested as a fuel for modified reciprocating engines.

The downdraft gasifier unit appears to be suitable for commercial application. The units can be sized up to 250 kilowatts and are transportable. These units are manufactured in Europe and include the feeder unit, gasifier unit, cyclone and generator. In addition, the unit would require reliable wood chippers.

The major concern for implementing the use of gasifier units was that of reliable and responsible operators. The units by the nature of the location of the feedstock would necessarily be used in northern Canadian communities.

3.2 ENGINEERING CONSIDERATIONS

3.2.1 Combustion of Mill Residues

The equipment required to fire wood in a boiler is similar to that for coal, however, due to the lower density and calorific value of the wood, larger physical units for both handling and burning the wood are required. One of the major differences between using wood versus coal is that wood has a high moisture content and therefore reduces efficiency to approximately 65% compared to 85% for coal-fired boilers. The furnace for wood burning would be different from that of coal in that coal is burned in a pulverized form whereas the wood is usually in larger portions such as chips.

The ash content of wood is much lower than coal, (i.e. approximately 1/20th) however, electrostatic precipitators are still required to remove particulates from the flue gas. As a result of the lower ash content, the ash conveying system would be significantly smaller than that for coal.

Recovery of the non-uniform material such as wood residue is best accomplished by chipping the wood. This allows for transportation and handling, nevertheless, the problem remains that 50% of the bulk of wood transported and handled is water. Access road and terrain significantly affect the efficiency of gathering wood and wood residue. Efficient harvesting of this energy resource is a major concern and if increased utilization of wood is to be achieved, there must be improvements in the modes and methods of delivery.

3.2.2 Wood Gasification

The primary method of producing wood gas is by the pyrolysis process which is performed at high temperatures and in a low oxygen atmosphere. Two methods of pyrolysis are employed , the fixed bed and the fluidized bed. The fixed bed operates in the temperature range of 1300°C to 2000°C, produces high energy conversion efficiency, low particulate emission and can process fuel with a high moisture content. The drawbacks to the process are with respect to ash removal, channelling and tar cleanup.

The fluidized-bed process prevents channelling by constantly agitating and mixing the fuel. The temperature range of operation is from 550°C to 1100°C. The lower temperature operation simplifies ash removal, extends reactor life, minimizes tar formation and reduces gas cleaning requirements, however, there are normally higher particulate emissions.

3.3 ENVIRONMENTAL CONSIDERATIONS

It is current practice that wood harvest waste products are often burned, buried or left to decompose. A major advantage of using wood as feedstock in the production of energy is that these former waste products can now be more fully and effectively used thereby completing the process of total utilization of this renewable resource.

There are, however, some environmental side-effects of directly converting wood (or any biomass) to energy. Similar to coal, though not nearly as pronounced, wood burning will produce NOX and particulate emissions as well as ash, but the sulphur emissions that are a common problem of coal-fired plants do not exist with wood due to the negligible traces of sulphur. As environmental control systems improve on coal-fired plants then it is expected that such systems will lend themselves equally to wood burning units.

The effects of wood residue harvesting operation are mixed. The removal of the residue reduces the chances of forest fires, however, brush piles have served as wildlife refuge and it is anticipated that the wildlife population would decline if the brush is removed. As well, there is little evidence of loss of soil nutrients if wood waste is removed.

3.4 ESTIMATED UNIT COSTS

3.4.1 Wood-fired Thermal Generation

In a recent study in Alberta, it was concluded that mill residues appear to be competitive with all other fuels, however, harvested wood was determined to be competitive only in isolated areas where cheaper fossil fuels were unavailable. The study determined that for a 20 MW wood-fired plant the unit capital cost would be approximately $1,350 (1978 $C) per kilowatt and unit annual operating costs would be approximately $0.03591 per kilowatt hour (1978 $C) more than twice as much as coal fired plants.

Where isolated areas rely on power from the region's electric grid and on individual energy supplies such as propane for heating and cooking, a central station wood-fired unit is currently uneconomic primarily due to low load factor utilization. If non-renewable energy costs continue to rise then wood-fired stations could well become economic within the next decade.

3.4.2 Wood Gasification

Wood gasifier units similar to the downdraft type being tested in Saskatchewan can be purchased for approximately $522 per kilowatt. Installation costs plus the addition of a wood chipping machine could raise the overall installed costs in the order of $1000 per kilowatt.

Analysis of levelized operating costs suggests that for a year round load factor of 42%, the costs of operating a wood gasifier unit would be approximately equal to the costs of diesel generation. One of the notable requirements for the wood gasifier unit to achieve such economies is that the wood feedstock would have to be gathered from within a 19 kilometer radius. However, as these units are reasonably portable then the feedstock range of the equipment can be expanded provided the load center shifts with the unit such as commonly occurs with northern campsites.

3.5 REMARKS

Utilities in North America which have relied on hydro, oil, natural gas and nuclear power plants are now actively researching biomass conversion systems as one of the energy supplements to meet their growing needs. It is likely that technological advances in the use of biomass for energy will occur more rapidly which will permit more economical and reliable use of biomass materials.

Saskatchewan is a likely candidate to incorporate wood biomass energy systems but presumably only in remote northern areas where feedstock is at hand, alternate fuels are expensive and power grid extensions are uneconomic.

4.0 WIND POWER

In this era of increasing concern over energy supply, the use of non-renewable resources and the effects on environment, wind power has re-emerged as a potential energy source. Government, industry and private developers are now focussing serious attention on wind power as a complementary energy supply for the current energy mosaic. Wind is second-hand solar energy; its basic driving force is the unequal heating of the earth and atmosphere. It is given characteristic flow patterns by the earth's rotation, however, the main odium against the use of wind power as a dependable energy source is that winds constantly shift in direction and vary in velocity. Therefore, the application of modern technology is largely devoted to harnessing these two variables to yield a more steady state energy supply.

Wind power researchers have generally approached development of this energy source by considering two system designs which would provide for:

1. A large number of small wind energy conversion systems (SWECS) (usual unit sizes range from 5 kW to 250 kW);

2. Large megawatt wind turbines (1 MW to 6 MW)

Both systems would be tied into the electric grid.

4.1 CURRENT DEVELOPMENTS

The United States appears to be one of the forerunners in planning for the use of large scale wind power complexes. In 1980, the U.S. Government approved The Wind Energy Systems Act which initiated an eight-year, 900 million dollar program to develop cost-effective wind power systems.

In New Hampshire, U.S. Windpower Inc. became the first commercial wind power producer with twenty 30 kilowatt 40 foot diameter, three bladed, horizontal axis wind machines connected to the Public Service of New Hampshire (PSNH) electric grid.

In Honolulu, Hawaii, Windfarms Ltd. is actively considering the installation of 20 four-megawatt wind machines on Oahu and to sell the energy to Hawaiian Electric.

The Southern California Edison Electric Utility has incorporated 800 MW capacity from wind power into their generation sequence plan by the year 2000. As well, some utilities in California have developed an experimental rate schedule which would allow customers with wind machines to hook up to the electric grid and thereby effectively utilize the grid as a storage shed.

In Saskatchewan, three variations of wind machines have been tested; a 1.5 kilowatt machine, a 50 kilowatt Darieus (egg-beater) machine supplied by the National Research Council and currently an 8 kilowatt Pratt and Whitney horizontal axis machine. The first machine proved less than satisfactory, the second has experienced bearing failures and the third has just commenced production. It is notable that the 8 kW machine is of suitable capacity to supply a farmstead operation and if successful such machines may soon be adopted by the rural community to supplement the electric grid supply.

With the completion of the installation of the New Hampshire units, commercial application was contractually realized with the 600 kW output being purchased by PSNH via a 20 year purchase power agreement. The producer is required to install and maintain the system, achieve and maintain approximately a 100% power factor, and will be paid 7.7 cents (U.S.) per kilowatt hour.

Larger "megawatt machines" are being actively considered by West Germany, Sweden, the United Kingdom, the United States and Canada. These large wind machines, which vary in design capacity from 1 MW to 6 MW, are now under serious development with estimated "on stream" dates as early as 1983. The January/February 1981 edition of the EPRI Journal speculates that by 1995, the United States will have installed its 100th 2.5 MW wind turbine.

From the Canadian perspective, wind machines would better serve isolated load areas where the costs of grid supply would be prohibitive and where diesel supply generation could be augmented by wind power in reducing energy costs. Typical examples are those locations with suitable wind regimes where cathodic protection units are operating off diesel supply. Bristol Aerospace Ltd. of Winnipeg, Manitoba, and the National Research Council are evaluating such systems which hold promise of reducing current wind machine energy costs by approximately 20 percent.

4.2 ENGINEERING CONSIDERATIONS

The availability of wind energy is highly site-specific and is subject to wide random fluctuations. The choice of location of a wind energy plant requires significant topographic and wind measurement research in order to select an optimum location which will minimize the unit cost of production of energy. Topographic factors that must be considered in such an analysis are:

- Level or hilly terrain
- Ground turbulence and airfoil effects
- Presence of valleys for venturi effects
- Forest cover and other material or man-made obstacles.

Recommended sites having the best potential for wind power are:

- Those with average annual wind speeds of at least 10 to 13 kilometers per hour
- Hilltops where the airfoil acceleration effect occurs
- Gentle plains
- Some mountain gaps or narrow valleys.

The primary attributes of these locations are the expected continuity of wind velocity and minimization of turbulence. The effects of varying wind speed are compounded by the fact that wind power varies as the cube of the wind speed, so that wind machines must be capable of accepting widely varying inputs if a large fraction of available energy is to be recovered. Mechanical and electrical limitations usually restrict the range of power levels that can be recovered.

An "aerogenerator" wind machine is primarily comprised of:

- A rotor
- A generator or alternator
- A voltage regulator
- A storage system
- A direct current to alternating current invertor
- A supporting structure.

Rotors are generally classified as either horizontal-axis, vertical-axis or cross-wind horizontal-axis. The rotor area is designed inversely proportional to the cube of the design speed for a given power rating in order to maximize air flow-through and pressure drop across the rotor.

The most economical design speed will involve a compromise between maximum recovery of available wind energy and maximum utilization of generating capacity.

4.3 ENVIRONMENTAL CONSIDERATIONS

Wind energy is essentially pollution free, as compared to conventional energy sources. The primary environmental concerns relate to the cadence and level of noise due to the rotor motion. As well, the visual impact would be significant particularly with respect to the larger megawatt machines with rotor diameters upwards of 60 meters, or with the multitude of smaller wind turbines that would be required for a similar output. The concept of wind farms would require dedication of large tracts of land to be set aside. Obviously, land usage will play a major role in determining site locations for such farms.

4.4 ESTIMATED UNIT COSTS

In studies performed in the U.K., a number of conclusions were drawn from an investigation of the sensitivity of generation cost to various parameters. The parameters having the most significant influence are mean and rated wind speeds, turbine diameter and wind machine cluster efficiency. For example, an increase in annual mean wind speed from 9.5 to 11 meters per second reduces generation cost by roughly 22%. An increase in turbine diameter from 80 meters to 100 meters reduces generation cost by roughly 20% and, as well, wider spacing of machines will improve total generation performance.

Various wind machine developments have yielded the following cost data:

Country	Aerogenerator Unit Capacity (kW)	No.of Units	Total Capacity (kW)	Estimated Capital Cost ($M U.S. 1980)	Estimated Installed Unit Cost ($U.S. 1980/kW)
U.K.	3000	1	3000	15.5	5200
U.K.	250	1	250	2.25	9000
U.S.A.	30	20	600	1.0 - 1.5	1700-2500
Canada	200	1	200	0.62*	3100

* 1977 cost of $465 thousand escalated at 10% per year to 1980 and assuming par with U.S. dollar.

The wide variation in as-built costs is indicative of the sensitivity of an installation's output due to wind regime, site location, design technology, design concept (ie. multiple small machines or fewer large capacity machines) and economies of scale.

It is generally anticipated that over the next decade unit costs for small and intermediate wind turbines should reduce in the order of a factor of 2.5 (constant dollars) while large megawatt machines could reduce in cost by a factor of 3.

Operating costs have to date been high for the early experimental wind power plants due to excessive down-time and poor component reliability.

The Synectic Group of Washington, D.C. suggested as a typical scenario, that a one million dollar, 500 kW wind energy system could achieve a pay-back within nine to ten years.

4.5 REMARKS

Research in the use of wind energy conversion systems is still within the learning curve process of development. It will be necessary to enhance the information data base by:

- Performing more extensive wind regime monitoring and correlating the data so as to optimize site selections
- Modelling generation from wind farms incorporated into the electric grid network and performing various stability studies to ascertain effects on the system and on the turbines
- Determining those components requiring a new technological approach rather than attempting to create less than optimum turbines from standard off-the-shelf components.

5.0 GEOTHERMAL

Geothermal energy is one of the earth's most plentiful energy resources. The subsurface temperature heat gradient rises approximately an average of 25 degrees Celsius per kilometer in depth. The earth's heat content can be tapped from hot water or steam which is either located naturally as subsurface water or from surface water that is pumped into deep reservoirs where it is heated and returned to the surface.

Man has long made use of this resource but only recently has attempted to extract the energy for commercial purposes.

In California, 200 megawatts of geothermal energy are expected to be connected with the power grid by 1983 while dry steam from The Geysers north of San Francisco have supplied electricity for a number of years.

Except for specific locations like those in California, the majority of North American geothermal "taps" are for direct use purposes. The heat content of equivalent depth wells, i.e., similar to those where electric plants are operated, is much lower and results in hot water generally from 30 to 60° Celsius. This hot water is used directly for space heating and thereby offsets energy derived from non-renewable resources which would otherwise be required.

A major problem associated with geothermal energy is that suitable sources are not always located near major population centers and the transport of the low heat content water would be impractical.

5.1 ENGINEERING CONSIDERATIONS

The basic components of a geothermal direct energy system includes a producing well, an injection well, piping, pumps and heat exchangers. The system is normally required to be a closed system due to the high salinity of the subsurface water. The water includes dissolved solids of calcium, magnesium, bicarbonate, sulphate, etc. and negligible amounts of dissolved oxygen.

5.2 ESTIMATED UNIT COSTS

The initial costs of constructing such a geothermal system is in the order of $1600-2000 per kilowatt (see comments below). The component costs are detailed below.

	($\$10^6$)
Producing Well	- 0.5
Injection Well	- 0.5
Piping, Insulation and Valves	- 0.3
Turbines, Pumps and Controls	- 0.3
Heat Exchangers	- 1.5
Housing	- 0.3
Other	- 0.5
	\$3.6 million (excl. land costs)

According to recent publications such a facility which produces 100 m^3/hr. of 74°C water and rejects it at 35°C is equivalent in gross heat terms of displacing 4.52 MW of electric power. However, actual displaced energy after pump, heat exchanger and transportation losses could yield less than 50% of the gross heat.

Operation and maintenance of these systems is relatively uncomplicated, however, the high saline content can result in salt deposition during cooling. Hydrogen sulphide is usually present but if the content level is low and the water is retained in a closed system to prevent aeration, then corrosion can be controlled. These problems lead to somewhat higher maintenance and reduced utilization. The general experience with geothermal operating and maintenance costs suggests that they range from 20 to 30% of oil-fired generation.

5.3 REMARKS

Geothermal power generation is currently impractical to consider for the Canadian plains areas. However, geothermal space heating is a feasible alternative provided the site location, water composition, and water temperature are appropriate and if maintenance can be reduced to more effectively utilize each geothermal complex.

6.0 FUSION POWER

Fusion power, the other nuclear option, can be considered as the most promising future option for supply of unlimited power. Controlled fusion power is the process of extracting energy from the fusing of hydrogen isotopes, which is directly opposite to the conventional nuclear fission power process which "splits the atom". The fusion process is one in which the electrons are stripped from hydrogen atoms by extremely high temperatures. The resulting medium, called a plasma, will consist almost entirely of positively charged nuclei (ions) and free negatively charged electrons. The ions then fuse and release energy.

The fusion process can generally be summarized as very highly technical with more readily acceptable safety and environmental features than with current fission processes.

6.1 CURRENT DEVELOPMENTS

The fusion process has been under active investigation since the early 1970's. A number of innovations have been attempted, all with the objective of increasing the "n.t" (plasma density and the confinement time of the plasma) such that the reaction energy recovered from the process can exceed the energy input to initiate the reaction. The product of the density and confinement time necessary for recovering all of the energy input is in the order of 10^{14} particles-seconds per cubic centimeter with a deuterium-tritium reaction, the likely first generation fusion reactor processes, to 10^{16} $\frac{\text{p-s}}{\text{cm}^3}$ with the second generation deuterium-deuterium reaction.

To achieve the proper "n.t" very high temperatures in the order of 100 million degrees are required. Current technology has achieved temperatures in excess of 60 million degrees but only an energy multiplication (Q) of approximately 1/10th the input. The TFT Reactor under construction in the United States and slated for operation by 1983 is expected to achieve temperatures of 100 million degrees and with output power at least equal to the input power which could provide the basis for subsequent "Q positive" reactors. Figure 3 graphically displays the "n.t" progress to date towards commercial operation.

The first Q positive fusion reactor is now under active consideration by the International Atomic Energy Agency (IAEA). The reactor known as INTOR (International Tokamak Reactor) is presently scheduled for design and construction through 1980 to 1989 with initial operation in 1989. (See Figure 4 for a time-frame reference for operating and proposed fusion reactors.) The purpose of INTOR is to provide the next step towards commercialization of fusion power. IAEA presently expects that the first commercial fusion reactors could be operating by approximately the year 2010. Further discussion in this section will be based on the INTOR system.

6.2 ENGINEERING CONSIDERATIONS

The Tokamak system's major components include a vacuum system - a large doughnut shaped vessel (Torus) in which the plasma is generated, a magnetic field system which proposes to use primarily super-conducting materials, a plasma heating system which uses a neutral beam injection system, tritium handling system, electric power system, diagnostic system, data acquisition and control system and auxiliary services such as water cooling, pumps, safety, etc.

This facility would require approximately 50 acres to house the reactor and provide facilities for administration, cafeteria, offices, central control room, and motor generator facilities. However, an additional 150 to 250 acres would be required for various environmental and safety concerns.

The INTOR facility would require very large pulse powers of 4 - 10 seconds with low power consumption. Pulse power would be delivered from motor generator systems connected to an external electric power grid. The power requirements for the facility are estimated at:

Peak Pulse Power:	1.5 GW
Average Power:	200 MW
Annual Power Consumption:	2×10^5 MW hrs (@ 1000 hrs operation).

6.3 ENVIRONMENTAL AND SAFETY CONSIDERATIONS

In the fusion power system, since energy has to be invested to maintain the reaction, there is no possibility of a runaway reaction as any change from the normal operation would tend to halt the process.

Other significant environmental concerns are:

1) Radioactive materials
2) Non-radioactive toxic material
3) Large magnetic and RF fields
4) Employment of high vacuum, large cryogenic systems and high voltage
5) Thermal emission.

The deuterium-tritium fusion process could generate approximately 5 tonnes/year of radioactive assorted waste. The fusion reactor radioactive waste materials will require careful disposal, however the radionuclide activity will be considerably lower in long lived components than that of a fission reaction, but still of the order of 10^7 years.

Current design concepts suggest that radiation emissions could be in the order of 100 Curie per year (1000 MW plant) resulting in a consequent plant boundary dosage of 3 mrem/year. This is negligible in comparison to the natural background radiation of about 130 mrem/year.

It is expected that beryllium or lead may appear in various parts of the reactor system and it is considered that technology to handle such materials is within the present state-of-the-art.

The torroidal field coils of a fusion reactor are required to generate magnetic fields of 10-12 Tesla using superconducting coils. Current information on the effects of large magnetic fields on human beings is unknown.

The heating processes which may be used in fusion reactors are readily controllable, however, safety measures for operating personnel requires further investigation.

Significant operational hazards could exist in relation to the high vacuum, large cryogenic and high voltage electrical systems.

The thermal emission environmental consequences of a fusion reactor will be of the same nature and scale as for thermal electric generating stations. This would involve microclimatic effects (ice fog), pollution from anticorrosion and biocide agents in cooling water, and airflow noise from mechanical draught units.

The advantage of the fusion reactor is that for a comparable output the efficiency of the fusion reactor is greater than most fossil fuel and nuclear fission reactors and therefore produces comparably less thermal pollution.

6.4 UNIT COST ESTIMATES

The general order of costs for a 5-10 MWe electric production INTOR facility are summarized below (1979 dollars).

I. Design and Construction ($1979 x 10^6)

	EDIA	HDW	INST	TOTAL*
Project Management	60	-	-	60
Safety & Syst. Eng. (1)	80	-	-	80
Tokamak System (2)	80	240	-	320
Electrical Power Sys. (Basic)	10	80	-	90
Experimental Area (3)	40	50	80	170
Architect-Eng. Serv.	15	-	-	15
Facility Construction (4)	-	5	145	150
Neutral Beam Sys.	10	100	-	110
Diagnostic Sys.	8	10	-	18
Instr. and Control	7	30	-	37
Blankets/Tritium, Mat. (5)	50	150	50	250
	360	665	275	1,300

*(Contingencies, fees, etc. are assumed be included)

EDIA = Engineering, Design, Inspection and Administration
HDW = Hardware
INST = Installation

II. Operation

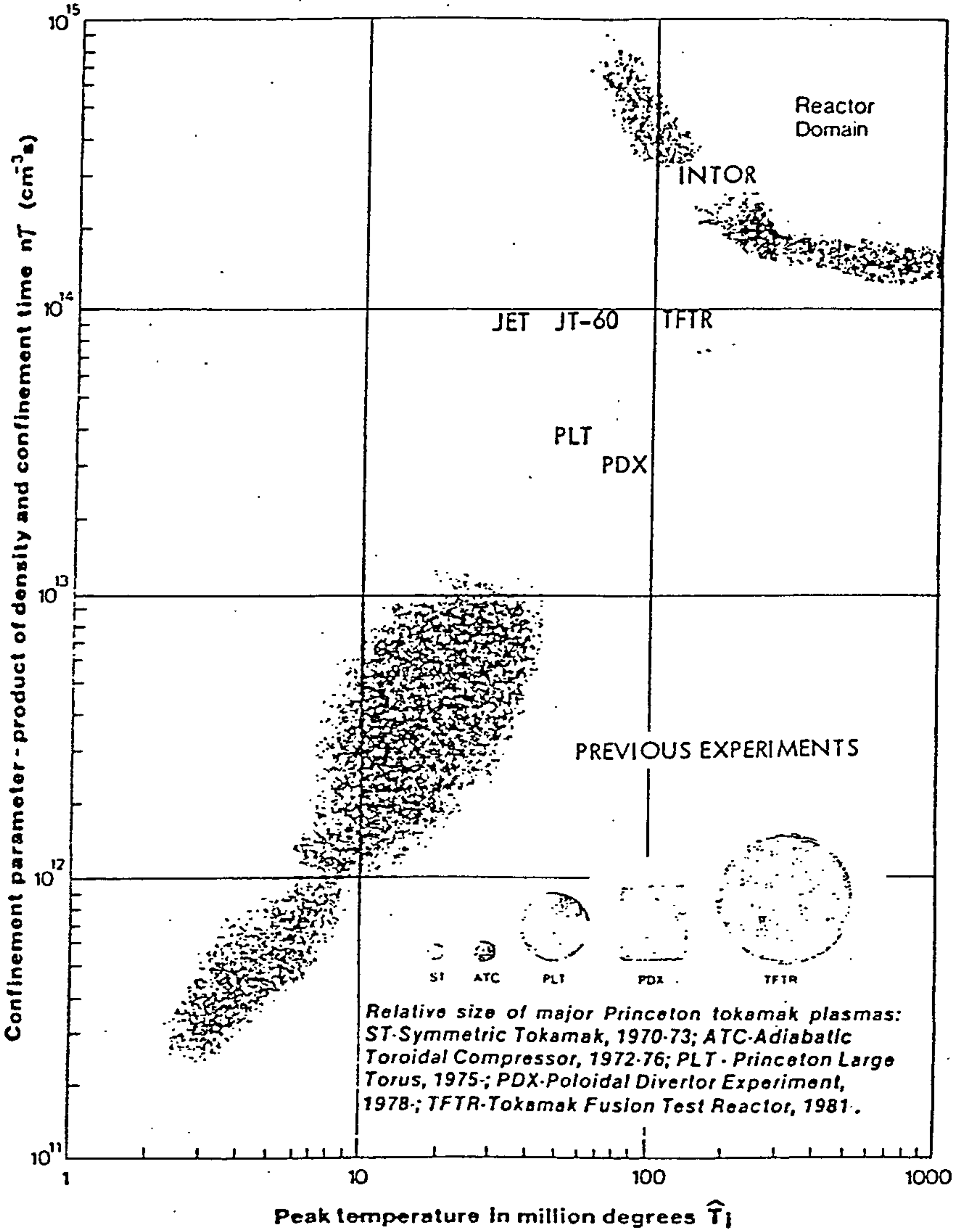
The estimated annual operating cost for this facility is in the order of $100 million per year, (1979 dollars).

Project definition, design and construction are estimated to require approximately 6,000 man-years and operations approximately 500 - 600 man-years per year.

6.5 REMARKS

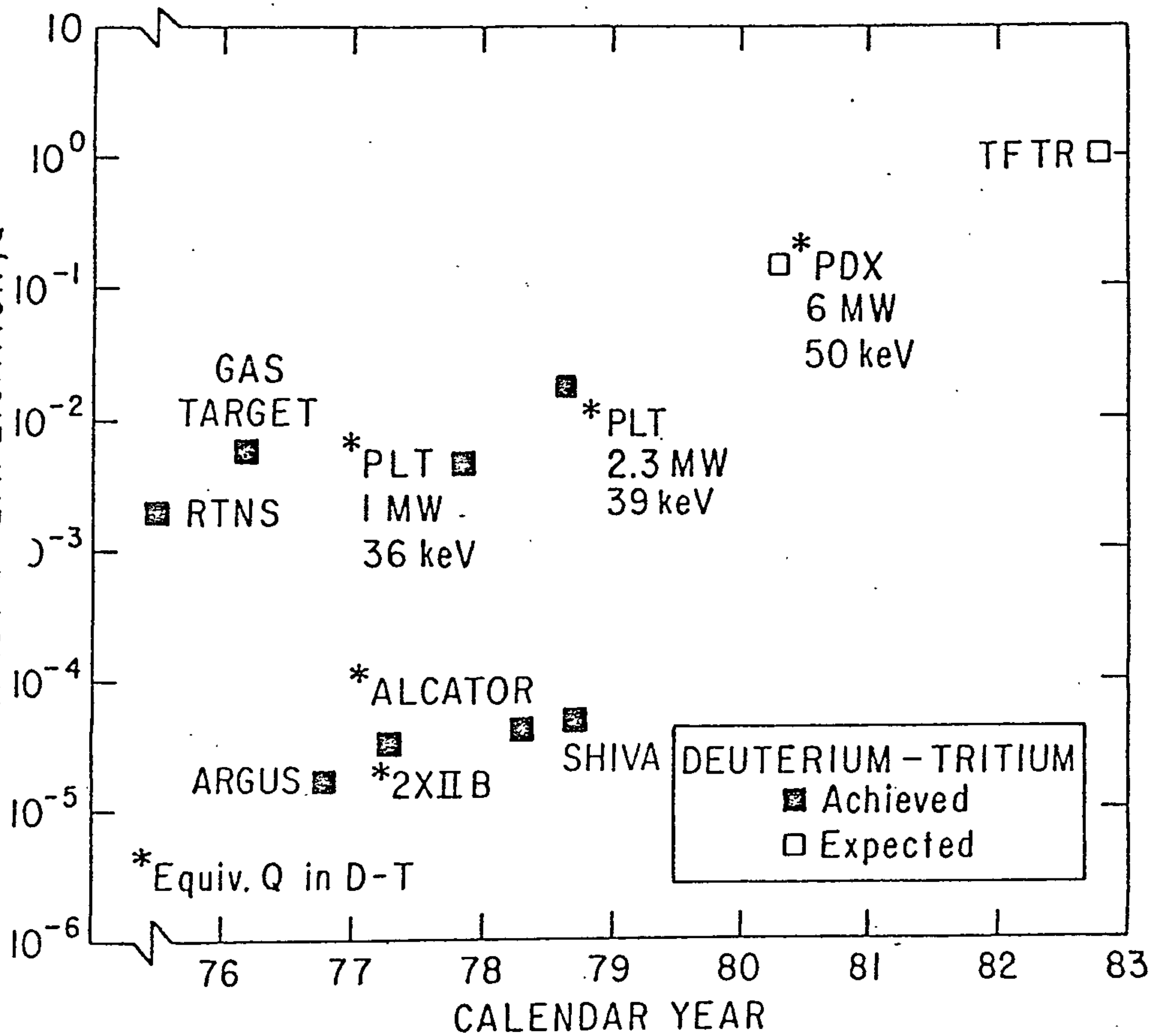
In general, fusion reactors are potentially promising as a viable power supply option. Benefits primarily include access to practically unlimited fuel resources, reduced thermal pollution and improved reaction control. The fusion process is on the threshold of breaking through to the "positive energy" state but futher development will be required. Fusion plants cannot yet be considered a serious option until this breakthrough occurs. Generation planning should therefore devote little time to this option at least for the near future.

FIGURE 3



Status of current and planned experiments

FIGURE 4



Progress towards achievement of energy break-even

7.0 HYDROGEN

Hydrogen is currently used in chemical, metallurgical and manufacturing processes. The hydrogen is produced by steam reformation or partial oxidation of hydrocarbons. More recently, electrolytic, thermal decomposition, thermochemical and photochemical processes are receiving global attention.

These various processes would produce hydrogen gas which could be either pressurized or liquefied for storage and/or transport to centers of consumption.

Hydrogen is attractive as a fuel as it contains the highest energy density per unit weight of any chemical fuel. Both the Lockheed Corporation and Boeing Company are examining conceptual jet aircraft designs where this property of hydrogen could be effectively utilized. These developments if actively pursued could produce hydrogen-fueled aircraft by the 1990's.

As a vehicular transportation fuel, hydrogen is a suitable replacement for gasoline, however, technical problems related to storage of compressed or liquefied hydrogen have promoted the use of metal and liquid hydrides. Metal hydrides effectively bind the hydrogen gas at pressures slightly above ambient pressure and below this pressure the metal releases the gas for subsequent use. Liquid hydrides are liquid compounds that contain hydrogen as a major element such as water, natural gas, propane and methanol.

The Special Committee on Alternative Energy and Oil Substitution commissioned by the Government of Canada has strongly recommended that as a long-term objective the Canadian energy system be based upon hydrogen and electricity as the principal energy "currencies".

This recommendation is based primarily on three major features of hydrogen:

1) Hydrogen is a substitutable fuel for hydrocarbons;
2) Hydrogen is relatively non-polluting;
3) This fuel can be "created" from a wide range of non-conventional power generation sources and can therefore act as an energy storage currency.

The last feature readily supports such variable power generation sources as solar, tidal and wind power where the "random" energy generated can be converted by electrolyzer units into hydrogen which can be stored for later use. Similarly, electric utilities could conceivably increase generation plant efficiency and reduce costs by producing hydrogen using off-peak electricity.

7.1 CURRENT DEVELOPMENTS

Electrolysis plants are in commercial use today such as the 90 MW complex owned and operated by Cominco Limited in British Columbia which produces hydrogen to be synthesized into ammonia.

Quebec Hydro has proceeded to the second phase of development whereby the utility has recently acquired a 5 kilowatt electrolyzer unit which will be supplied with simulated wind energy.

7.2 ENGINEERING CONSIDERATIONS AND ESTIMATED UNIT COSTS

Electrolyzers are manufactured in a variety of capacities from the low kilowatt capacity up to 250 megawatts or more. In the larger units, capital costs have been reduced to the $250 to $300 per kilowatt range.

The heat content of hydrogen gas is almost one third the heat content of a similar volume of natural gas, which therefore suggests that for equivalent power output, larger storage is required.

A scenario for using hydrogen in an electric power generation mode would provide for off-peak power from current generating stations producing hydrogen through means of the electrolyzer. The gas is then compressed and stored for subsequent conversion to electricity during peak demand by means of a fuel cell and DC/AC invertor. However, this process from the production to utilization of hydrogen is estimated to be less than 35% efficient and does not take into consideration the efficiency of the initial process of first producing electricity.

The Special Committee suggested that it would make more sense to produce hydrogen, mix it with natural gas, and transport the mixed gas via pipeline for subsequent use as a fuel.

Hydrogen electrolyzers are relatively easy to operate and maintain as they are essentially static automatic units. Manufacturers suggest that such units may continue to operate for ten to fifteen years between overhauls and even then, the overhaul work is primarily related to cleaning the cells and replacing electrodes.

Fuel cells currently require the use of expensive electrodes which are relatively short-lived. As well, care must be taken to avoid contaminating the electrolytes used in the fuel cells.

7.3 ENVIRONMENTAL CONSIDERATIONS

Within an electric energy context, hydrogen would be produced by electrolyzers "driven" by electric generation sources. A number of these sources (solar, tidal, wind) are non-polluting and therefore the overall process is a relatively environmentally clean process. The environmental effects of other drivers such as coal-fired, wood-fired and nuclear plants have been referred to earlier.

Hydrogen combustion in the presence of air releases water and nitrous oxides which reflects a significant improvement over hydrocarbon combustion which releases carbon monoxide, carbon dioxide, nitrous oxides, and hydrocarbons.

From the aspect of public safety hydrogen has had to rebound from its "Hindenberg syndrome". Although hydrogen is combustible, it is argued that it can be handled safely. Should it be ignited after a tank rupture, then the burning gas would escape vertically and probably jeopardize those nearby less than the conventional liquid fuels which tend to spread horizontally.

7.4 REMARKS

Hydrogen as an energy currency offers promise of effectively harnessing and utilizing non-conventional power sources. The electricity-hydrogen system envisaged by the Special Committee proposes to integrate and efficiently utilize all conventional and non-conventional power sources and reduce dependency on the hydrocarbons. If this scenario is to unfold then vital research must be encouraged so as to improve the overall energy efficiency of hydrogen production and utilization as well as to develop and/or modify processes, systems and vehicles to use hydrogen.

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DRAFT REPORT

NUCLEAR GENERATION OPTION

Prepared For

SASKATCHEWAN POWER CORPORATION

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May 1981

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1 INTRODUCTION

This section provides a brief discussion of nuclear power generation utilizing the Candu technology in order that Saskatchewan Power Corporation may evaluate this technology as a potential option in meeting future generation capacity requirements.

Nuclear power generation employing Candu technology is currently a viable alternative for many electric utilities and is considered by those employing the technology to be both economically and environmentally competitive with other methods of generation. If present trends continue, the nuclear option will become of increasing importance to Saskatchewan Power Corporation due to:

- increasing prices and reduced supplies of fossil fuels which will force conversion to electricity by the public and development of alternate methods of generation by utilities;
- movement towards higher coal prices due to coal-based chemical development;
- possible increased operating costs of thermal coal generation caused by increased transportation, coal costs and costs of pollution control;
- improved technology, operating power factors and continuation of the environmental and safety record of the Candu system;
- the potential for an integrated nuclear energy industry in Saskatchewan providing security of price and supply of nuclear fuels.

The benefits of nuclear power may be offset by the following limitations which are dependent on local conditions and the utility's requirements:

- public concern for reactor safety and spent fuel disposal may impede nuclear development schedules;
- the high capital costs and long lead times (10-14 years) may not fit the capital structure, financing or schedule requirements of the utility;
- the minimum 600 MWe unit capacity may be too large to meet

system capacity addition requirements. (This factor may be overcome if the Western Grid or exports of surplus power to the United States were available.)

The information contained in this report was derived from various literature sources particularly British Columbia Hydro and Ontario Hydro. The data is intended to be of a general nature. The costs are typical only and are based on the minimum Candu unit size of 600 MWe capacity. Its purpose is to provide a basis for evaluating the relative costs, schedule and requirements compared to current near-term alternatives being considered by Saskatchewan Power Corporation.

2 PLANNING AND PREPARATION

2.1 Project Schedule

Nuclear generating installations typically have a 10 to 14 year lead time from the decision to proceed with nuclear generation to commercial operation of the first reactor. This schedule can be extended or shortened depending on the degree of public acceptance of the concept and the facility. The overall process has four major phases:

Phase I	- Pre-investment studies	6 - 18 months
Phase II	- Site investigation and selection including environmental studies, public review and debate, preliminary planning, contact with licencing and regulatory agencies	2 - 6 years
Phase III	- Preliminary engineering and cost estimates, site approval, project approval, construction licence, financing and project organization	1 - 2 years
Phase IV	- Engineering, construction, operator training and commissioning	6 years

These phases are broken down by major project work packages in Attachment I.

The schedule requirements for Phase II completion are uncertain for any nuclear development in Saskatchewan. The Saskatchewan Department of Environment would require at least two years for public review, debate and hearings prior to approval to proceed. The timing would depend on how well this phase is planned, the extent of involvement by experienced nuclear consultants and the efforts put forth in nuclear information programs.

2.2 Public Review

In 1979, the Atomic Energy Control Act was revised to include the mandatory public hearings prior to issuing a licence to construct a nuclear plant. The fate of nuclear power, like any technology related to major energy projects, does not depend on its economics, safety record, efficiency or reliability but on public acceptance. Prior to March 1979 and the Three Mile Island accident, public concern centred on waste management and disposal, but now reactor safety and the effects of low level radiation releases appear to be the major concerns. Atomic Energy Canada Ltd. (AECL) is conducting an in-depth study to demonstrate the feasibility of and security of waste immobilization and emplacement in deep underground, stable geological formations and there is optimism that, by 1985, this barrier to public acceptance will be removed well in time for any nuclear development in Saskatchewan. Reactor safety, however, will remain an issue mainly due to misunderstanding and misconceptions. A utility considering the nuclear power option is well advised to institute a nuclear information program well in advance of proceeding in order to ensure a fair and productive debate on the benefits and costs of nuclear technology.

2.3 Site Investigation and Selection

This section details the normal steps, procedures and major considerations involved in site investigation and selection. The total siting process entails a complex set of requirements to produce a Site Evaluation Report for submission to the Atomic Energy Control Board (AECB). This report is one of the regulatory prerequisites to issuance of a construction licence.

2.3.1 Selection Procedure

The site selection procedure for a nuclear installation is typical of any large project. First, the candidate areas are screened to determine possible regions. Potential areas within the regions are then evaluated and candidate sites are analyzed and selected. Finally, the candidate sites are studied to select the preferred sites for final evaluation and selection of a site for development.

2.3.2 Factors Considered in Site Selection

The following is a discussion of the major factors involved in site selection and the elements considered in each category:

(i) Site Physical Characteristics

A typical plant area is approximately 370 meters by 610 meters with an exclusion zone of 1000 meters diameter, necessitating a total area of 315 hectares. If the plant is located on a large body of water, the land area required is reduced to 160 hectares.

(ii) Access

The transportation facilities, by land or water, to the site are important due to the size and weight of the major components. Good transportation facilities allow more shop assembly of the major components resulting in time savings and better quality control. The turbine and generators for a 600 MWe unit weigh 200 to 300 tons and the reactor vessel weighs 300 tons to 600 tons depending on the degree of pre-assembly.

(iii) Topography and Hydrography

To minimize pumping costs of water supplies, a site near a river or lake with a low elevation relative to the water level is desirable. A rocky lake or river bed is preferred to minimize silt entering the cooling system.

(iv) Geology and Seismology

The bedrock should be close to the surface, impermeable, and free of active faults and major passive faults within a ten mile and a one mile radius, respectively, of the plant. A zone of low seismicity is preferred. Typical plants are designed for a 0.2 g standard design base earthquake level which appears compatible with most locations in Saskatchewan.

(v) Water Supply

The Candu nuclear station releases about 70% of the heat generated to the cooling system. The cooling system options are once through and a closed cycle system employing cooling towers. The once through cooling system requires about 7,000 gallons per second of cooling water per 600 MWe unit with the closed cycle system requiring about 4% make-up water to replace evaporation losses.

(vi) Population

An area of low population is preferred. However, Ontario Hydro has installed nuclear generating facilities near large population centres. The extra costs of improved containment facilities were justified by the savings on transmission costs.

2.4 Preliminary Engineering Requirements

A Plant Technical Description is prepared containing the design basis, technical specifications, layouts, cost estimates and schedules for the site selected in previous studies. This report provides a basis for preliminary approval of the project. A decision is made at this point as to the extent of owner group participation in the detailed design and procurement. Saskatchewan Power Corporation would require the assistance of a nuclear power consultant since it has minimal nuclear experience.

A work breakdown should be prepared detailing the engineering responsibilities of the utility, the consultants and the AECL. Saskatchewan Power Corporation may take on minimal responsibilities in the design of the plant and specification of equipment and in essence receive a "turn-key" operation from the consultants and AECL. A utility with thermal plant experience may carry out the engineering and manage the thermal plant, leaving the nuclear steam supply to consultants and AECL.

3 ENGINEERING AND COST DATA

3.1 Capital Costs

This section contains tables summarizing the capital cost estimates and capital cash flows for a single 600 MWe Candu unit with once through fresh water cooling and mechanical draft cooling tower alternatives. The cooling tower alternative is presented as a differential cost to the once through cooling system. Utilities of the size of Saskatchewan Power normally approach the nuclear option with one 600 MWe basic unit and add capacity by 600 MWe additions to a potential four unit 2400 MWe plant. The additional units will normally cost about 10% less than the overall cost of the first unit.

The mechanical draft cooling tower alternative results in increased capital costs and reduced net power output of the plant due to power consumed in increased cooling water flows and operating cooling tower fans.

Table 3-1 below gives the capital costs of a typical 600 Mwe Candu unit and Table 3-2 shows the estimated increase in capital costs and reduced output for the cooling tower option. These estimates are based on data provided by AECL. Table 3-3 indicates the cash flow during the 6-year construction phase from site acquisition to commercial operation as provided by AECL.

3.2 Operating Costs

Table 3-4 provides a summary of the estimated operating costs for a 600 MWe Candu unit based on figures provided by AECL. The operating costs for both cooling water alternatives are considered to be similar since the cooling tower effect is considered in plant output. Excluding fuel, the operations and maintenance costs of a nuclear plant are estimated to be approximately 50% greater than for an equivalent coal fired plant. A typical breakdown of operating and maintenance costs excluding fuel, heavy water and waste disposal is presented in Table 3-5.

Attachment 1

Major Project Work Packages

1) Pre-Investment Studies

- nuclear information program
- government authorization of nuclear planning
- public debate/inquiry/review
- approval to proceed with nuclear project
- Candu feasibility studies
- seismic investigations
- establish site selection criteria
- nuclear planning studies
- nuclear project pre-feasibility report
- establish nuclear project group

2) Site Selection and Environmental Assessment

- appoint consultant
- preliminary site investigation and selection
- environmental studies
- preliminary site evaluation report and site cost estimates
- conditional site approval
- property options
- detailed site evaluation and site evaluation report (SER)
- site application
- final site approval
- site acquisition

3) Preliminary Engineering and Construction License

- conceptual design
- detailed cost estimates
- project technical description
- preliminary safety analyses report
- construction license application and public hearing
- project approval by SPC
- construction license received

4) Engineering Design - Construction and Commissioning

- engineering design and construction
- operating staff recruitment and training
- commissioning

Table 3-1

Candu 600 MWe Nuclear Thermal Plant

Capital Cost $\$ \times 10^6$ July 1981

Costs to License (Pre-Construction)	6
CONSTRUCTION:	
Site Acquisition (200 hectares)	3
Site Preparation	10
*Direct Plant Costs	703
Heavy Water Inventory	150
Initial Fuel Inventory	15 ok
Spare Fuel	18
Operator Training	8
TOTAL DIRECT CONSTRUCTION COST	913
Construction Insurance and Bonds	15
Indirect Costs/Engineering/Management Field Supervision and Commissioning	269
Contingencies	91
TOTAL PROJECT CAPITAL COST (less transmission)	1288
*DIRECT PLANT COSTS:	
Buildings and Structures	145
Reactors, Boilers and Auxiliaries	240
Turbine Generator and Auxiliaries	128
Electric Power Systems	58
Instrumentation and Control	48
Services	64
Construction Plant	20
TOTAL DIRECT PLANT COSTS	703

BASIS:
- Net Power to Grid 630 MWe ?
- Once through fresh water cooling
- Corporate overhead and interest during construction excluded
- Specific Power Costs = $2044/kw
- .2 seismic design basis
- Contingency at 10%

Table 3-2

Cooling Tower Alternative

Capital Cost $\$x10^6$ July 1981

Reference Plant Capital Cost	1288
Additional Cost Mechanical Draft Cooling Towers	60
TOTAL CAPITAL COST	1348

BASIS: . Net Power to Grid 604 MWe
. Specific Cost = $2232/kw

Table 3-3

Cash Flow During Construction

$\$x10^6$ July 1981

Year	Capital Cash Flow % of Total	Cash Flow
1	8	103
2	17	219
3	25	322
4	26	335
5	18	232
6	6	77
	100	1288

BASIS: . Once through fresh water cooling

Table 3-4

Total Operating and Maintenance Costs

600 MWe Candu Nuclear Thermal Plant $\$x10^6$ July 1981

Operating and Maintenance	12.0
Heavy Water	4.1
Fueling	16.7
Waste Disposal	.6
	33.4

BASIS:
- 80% annual capacity factor
- average plant output 4471 GWh/year
- Heavy water at \$320/kg Fuel at \$32/kg UO_2

Table 3-5

Typical Breakdown of Operating and Maintenance Costs (excluding fuel, heavy water and waste disposal)

600 MWe Candu Nuclear Thermal Plant $\$x10^6$ July 1981

Labour	63%
Materials and Consumables	16%
Purchased Services	17%
Other	4%
TOTAL	100%

Note: Labour cost includes overhead costs.

4 ENVIRONMENTAL IMPACTS

4.1 Environmental Considerations

Environmental considerations associated with nuclear generating stations have always been a major factor in nuclear technology. The nuclear industry is the most highly regulated and controlled industry in Canada. This has been beneficial to the industry since is has resulted in an excellent environmental and safety record compared to other total generation options. The Candu nuclear generating system is considered to have a narrower range of environmental impacts than an equivalent fossil fuel plant. The nuclear station produces more waste heat but air pollution is essentially non-existent.

The environmental impacts of nuclear stations are viewed as being of two types: the non-radiological and the radiological impacts. The Atomic Energy Control Board and its committee, the Reactor Safety Advisory Committee, have responsibility for all aspects of the effects of radioactive material on the environment. The non-radiological effects of a project are left to the other federal, provincial and local agencies. The Federal Department of Environment will accept provincial procedures for the environmental aspects of nuclear plant siting only where the provincial standards are more stringent than the federal requirements. In a province such as Saskatchewan, which has no nuclear power industry, the Federal Environmental Protection guidelines can be adapted for siting nuclear plants. The AECB, under the provisions of the Atomic Energy Control Act, licences the construction and operation for all nuclear power plants in Canada. They also control all aspects of the fuel cycle in operating units.

Environmental studies are carried out during three major phases of adding new generation facilities: site selection; site development and construction; and commissioning and operating. The environmental criteria for evaluating the siting and construction phases of nuclear generating plants are similar to those for fossil fueled plants although, from an environmental standpoint, each plant is considered unique.

During operations there are two differences in potential impact. Nuclear plants have a thermal efficiency of about 29% compared to 39% for a typical fossil fuel plant which results in approximately a 60% greater heat release to the environment. The second difference is the possible release of radioactive materials to the atmosphere and water.

If cooling towers are employed, the plume effect will be greater than for fossil fuel plants. This may be of significance in Saskatchewan with its climate of dry, cold winters and may require facilities to preheat cooling tower exhaust. Cooling towers will also result in some radioactivity released into the atmosphere but will be well below (i.e. 1%) the design maximums.

4.2 Siting Stage

Environmental studies should commence early in the site selection stage and each site evaluated as to the environmental impacts which may occur from construction and operation of a nuclear plant at the site. Costs of environmental studies at this stage have been estimated at about $500,000 but may be much greater depending on the locality of the plant and the extent of public acceptance or opposition. Ideally, background radiation studies would have been undertaken over the previous years by the utility in a number of potential sites in the province.

4.3 Construction

Impacts due to nuclear plant construction are the same as the impacts caused by construction of any other type of power station of comparable size.

4.3.1 Air

Air quality will be affected by dust from earth-moving, any rock crushing operations, and by burning of construction waste on-site. Offsite dust will arise from heavy traffic and from hauling construction materials such as aggregate, concrete and rock fill. The air quality will not be altered appreciably by the operation and any effects will be temporary and localized.

4.3.2 Water

Construction of cooling water intake and discharge may require dredging and blasting which will affect the local area temporarily. The area should return to normal after construction activity ceases.

Commissioning chemicals (fluoroscein, morpholine and hydrazine) can be discharged to a sewage lagoon until cooling water discharge is available for dilution. Sewage and surface drainage may affect water quality temporarily during construction and may be treated in stabilization lagoons designed to Ministry of Environment standards.

4.3.3 Noise

Sound pressure levels during construction could reach 85 dBA in the work area from some construction equipment but should not affect local communities since most construction will be in the centre of the 1000 m exclusion zone.

4.3.4 Site Improvements

On completion of construction the plant area should be sloped, graded and sodded. Trees should be planted and roads and parking lots paved.

4.4 Operations

4.4.1 Atmospheric Emissions

During operations, purges of closed ventilation systems may occur through stacks. These effluents are monitored for radioactive emissions and may require filtering or discontinuence of purges. Experience at Ontario Hydro's Pickering site has revealed some concentrates of tritium in the range of 0.1% of the maximum allowable.

4.4.2 Aquatic Emissions

Thermal discharges for a nuclear station will have similar effects as fossil fuel plants in the aquatic environment but will be of a greater magnitude due to the larger amount of heat released. The once through cooling system will require detailed studies of the site intake and outlet locations to minimize the entrapment of fish and the effect of the heat content of the discharge water.

4.4.3 Radioactive Liquid Effluents

All liquid effluents which may contain activity are monitored and contained making it highly unlikely that the limit for continuous releases will be exceeded during normal operations. Stations are designed for a target release of 1% of the Designed Release Limit (DRL) calculated for the particular station. Maximum permissible concentration for liquid effluents is set by the AECB.

4.4.4 Other

Agriculture, wildlife and vegetation should be affected less than by an equivalent fossil fuel plant since no flue gas is produced. Oil, condensor cleaning chemicals, boiler blowdown, and water treatment plant effluents can be handled similar to other thermal plants.

5 SOCIAL AND ECONOMIC IMPACTS

The social or economic impacts of a large power plant project imposed on the local communities should be considered at the initial site selection stage and continued throughout the construction and commissioning phases to the full commercial operation of the facility. The impacts generated by a nuclear plant are similar in nature to those of a thermal plant but are greater due to the longer construction period, larger construction work force and somewhat higher operating staff requirements.

This section details the study requirements, the nature of the impacts to be considered, and the typical process.

5.1 Impact Study Requirements

The Environmental Assessment Act requires the preparation of an Environmental Impact Statement for any large energy project. Since any nuclear option will be a first for Saskatchewan Power, the study requirements should be detailed and confirmed with governmental regulatory bodies at the outset of the project. The purpose of the studies is to determine the impacts, both positive and negative, on local communities due to construction and operation of the plant. The studies should be commenced during the site selection stage and continued for site alternative evaluation and throughout the construction and operation phases of the project.

5.2 Extent of Studies

Impact studies will normally include all communities within a 25 mile radius of the facility but will also include those at greater distances if significant impacts are expected to occur. The communites studied should be involved throughout the total study process to ensure all issues are considered, to provide data on existing and projected community facilities and to review the findings prior to report completion.

5.3 Socio-Economic Factors Considered

The detailed requirements of the studies are defined for the specific project but should include the effects on the following factors for local communities during the construction and operation of the facility:

Employment - including labour availability, wage rates, etc.

Population - regional and local

Housing

Economic Activity - local and regional

Municipal Financial Conditions

Historical and Archaeological Significance

Land Use, Plans and Objectives - regional and local

Municipal Services Requirements and Costs:
- sewage collection and treatment
- water treatment and supply
- solid waste collection and disposal
- health
- reacreation
- libraries
- education
- roads
- police and fire protection
- municipal administration, including administrative costs, municipal planning and zoning.

5.4 Study Process

The following details the normal course of the impact studies during the various phases of the project.

5.4.1 Site Selection Stage

Studies are initiated as early as possible during the site selection stage. The Terms of Reference for the study are reviewed and prepared with the community and from this the study team, usually independent municipal consultants, will establish the base conditions for the community and a monitoring program to evaluate the impacts through the project construction, start-up and operating phases.

Actions are planned to minimize negative impacts and maximize positive impacts over the project schedule. The monitoring program usually takes the form of a questionnaire directed at the community at six month intervals. Unforeseen difficulties are corrected with remedial actions approved by various participants as they occur.

5.4.2 Construction Stage

As construction progresses, unforeseen difficulties are detected by the monitoring program and corrective actions are taken. At the peak construction period a further study should commence to determine the costs and benefits which have occurred by comparing the current conditions with the projection of the base case had the construction not commenced. An assessment of the effectiveness of actions taken to mitigate impacts as well as a review and update of the initial forecast on community impacts are made at this stage.

5.4.3 Commissioning and Operation

Monitoring continues after construction and during initial operations on a regular basis. After three years of operation, the frequency and degree of monitoring is reduced. Continuing some degree of monitoring over the project life is becoming common practice.

5.5 Manpower Requirements

Table 5.1 below provides an estimate of the total construction, operating and commissioning manpower requirements over the 12 year life of the project. Table 5.2 gives the breakdown by trade of the peak labour force required during construction.

The manpower estimates were prepared by factoring and extrapolating labour estimates for larger units and should be considered as approximations for estimating local impacts and labour supply requirements.

Table 5.1

Total Construction, Operating and Commissioning Manpower Requirements For 600 MW Station

Year	Construction	Operating	Total
1	135		135
2	170	10	180
3	250	40	290
4	400	175	575
5	800	225	1025
6	1400	300	1700
7	1200	400	1600
8	600	350	950
9	150	290	440
10	50	270	320
11		250	250
12		250	250
TOTAL MAN YEARS	5155	2560	7415

Table 5.2

Peak Construction Labour Force By Trades

Carpenters	125
Labourers	130
Machine Operators	35
Concrete and Rebar Workers	60
Pipefitters	160
Iron Workers	50
Welders/Boilermakers	70
Millwrights	60
Electricians	120
Insulators	15
Roofers	10
Boiler Erectors	10
Turbine Generator Erectors	40
Painters	30

6 PERIPHERAL COST AREAS

6.1 Waste Management

6.1.1 Spent Fuel

A typical Candu nuclear generating station produces approximately 140 kg (6 fuel bundles) of spent fuel per year per 1 MWe capacity. This is over 99% of the radioactive material produced in a nuclear station. A 600 MWe unit will produce about 8500 cubic feet of spent fuel in 30 years of operation. Spent fuel is initially stored underwater in the spent fuel bays included with each Candu reactor which are designed to store 10 years of production. Spent fuel is eventually transferred to a centralized storage facility employing the water filled bay concept or concrete cannisters. Spent fuel may undergo reprocessing in Federal Government owned facilities.

Current proposals are for fuel and radioactive waste from reprocessing to be permanently stored deep underground in geologically stable strata isolated from man's environment. Cost of the complete spent fuel disposal is estimated at less than 0.1$/MWhr (1979) including labour and not including transportation.

6.1.2 Medium and Low Level Wastes

Ion exchange resins, filters, non-combustible objects (metal, glass, etc.), combustible articles (paper, wood, mops and rags, used protective clothing, etc.),and organic fluids (oils, chemicals, etc.) make up the medium and low level wastes. A typical plant includes facilities for the collection and preparation for on-site storage and offsite disposal. Final storage methods depend on the local requirements and utility policies.

Radioactive wastes other than spent fuel are managed within the following guidelines:

- process for reduction (incineration, acid digestion of resins, etc.)
- immobilize and, where applicable, solidify in non-soluble form
- use multiple confinement storage systems
- monitor storage containments for leaks
- final disposal deep underground
- isolate from groundwater at all stages.

Waste storage requirements for a 600 MWe unit are in the order of 400 m^3 for the life of the plant and cost approximately \$305 M (1977) including incinerator facilities and labour for the life of the facility. Since the on-site storage facilities may degrade prior to the required length of isolation (100 years), continuous monitoring for leaks and of containment facilities is employed. Long-term care of facilities or possible transfer to replacement facilities may be required. Low and medium level waste disposal cost approximately \$0.1/MWhr (1979) giving a total waste management cost of \$0.2/MWhr. This is about 3% of the cost of nuclear generated power from Ontario Hydro's Pickering plant.

6.2 Decommissioning

Nuclear generating facilities have a 30 year life based on financial depreciation. The useful life may be greater depending on the economics of maintenance and rehabilitation vs decommissioning and replacement. If the trends to increased nuclear power generation continue, the economics appear to favour rehabilitation over decommissioning. However, should the decision be made to decommission a facility there are three options available, any one of which can be taken directly or carried out in stages. All three options involve reactor shutdown and storage of all fuel and radioactive wastes.

6.2.1 Option 1 - Mothballing

In this option, the primary containment systems are maintained and all systems containing radioactive liquids are drained and sealed. The secondary containment systems are maintained. To ensure potential radioactive releases are no more than for normal operations, control of atmosphere inside the containment building is continued. The inside and outside of the facility are monitored and inspected to ensure security and safety. The process typically requires one year to complete.

6.2.2 Option 2 - Entombment

All accessible equipment and all materials posing a long-term health hazard are dismantled and removed. The facility is sealed off and surveillance and monitoring maintained at a minimal level to ensure leaks do not occur to the entombment structure. Four years are required to complete.

6.2.3 Option 3 - Dismantling and Removal

All radioactive materials are removed and the site released for unrestricted uses. No surveillance or inspections are required after completion, with total dismantling completed in 6 years.

6.2.4 Decommissioning Costs

Costs of decommissioning a nuclear generating facility are estimated at about 5% of the original capital cost and are less than the salvage value of the heavy water inventory. Decommissioning costs ($ 1981) are estimated as follows:

	Cost	Annual Cost	Time
1) Mothballing	$10 M	$130,000	1 year
2) Entombment	$29 M	$100,000	4 years
3) Dismantling	$50 M	- 0 -	6 years

6.2.5 Industry Experience

The nuclear industry has successfully dismantled and decommissioned nuclear facilities safely and with minimal environmental impact. Present techniques and capabilities enable all three possibilities to be carried out safely and economically.

6.3 Staff Training

AECL provides operator and specialist training as part of a contract to enable the customer to manage and operate the facility. Trainees selected are normally graduate engineers with at least six months experience in power plants or equivalent operations and completion of a preliminary training program on power plant engineering and nuclear technology. Trainees are required to pass examinations on nuclear and conventional generating operations and design, and radiation protection.

Training usually commences during the first year of the design and construction phase. Trainees may work with the design engineers or with AECL preparing commissioning and operating procedures. Final training takes place during commissioning of the facility and continues until the operations are turned over to the utility. Normally two years are required to achieve basic qualifications and four years of power station experience are required to achieve a nuclear station operator level.

Ontario Hydro provides training for other utilities in nuclear plants and simulators. Charges for training are in the order of $2,000/week using nuclear stations and a simulator, not including living expenses. It is estimated that the total training cost for a 1200 MWe unit staff is about $6 million.

The costs of training operators and other staff are included as part of the capital cost of the plant as detailed in Table 3-1. Table 6-1 details the operators and specialists who would require AECL training.

Training of other staff in nuclear operations safety can be carried out locally, and additional operators and specialists can be trained on-site during plant operations utilizing AECL start up staff.

6.4 Monitoring Programs

AECB, as part of station licencing, requires continuous radioactive monitoring and reporting. Station effluents are limited and all are monitored on a regular basis with continuous monitoring on the cooling water system to detect leaks from the primary system. Besides the station monitoring, offsite environmental monitoring programs are carried out by the utility and government agencies on air, water, and precipitation as well as fish and locally produced milk. The utilities maintain on-site stations and offsite reference stations to monitor the following:

1) Ambient gamma dose by a TLD meter (Thermal Luminescent Dosemeter). Readings are taken four times a year.
2) Air: Monitoring is performed by means of various filters and samples are taken monthly. The air is checked for its content of Tritium Radioiodines and Particulates.
3) Precipitation: samples are taken monthly and analyzed on a quarterly basis.

A typical monitoring station requires a 400 square foot fenced area at a cost of $20,000 per station.

Table 6-1

Operations Training	Number
Superintendent	1
Assistant Superintendent	1
Generation Section Chief	1
Shift Supervisors	4
Control Room Operators	12
Training Co-ordinator	1
Technical Support Chief	1
Physicist	1
Nuclear System Process Engineers	2
	24

Specialist Training	
Physicist	1
Mechanical Maintenance Supervisor	2
Electrical Maintenance Supervisor	2
Instrument and Control Engineers	3
D_2O Management Engineers	2
Chemist	1
Health Physicist	1
Fuel Handling System Engineer	1
Fuel Handling Mechanical Maintenance Engineers	2
Fuel Handling Control Maintenance Engineers	2
Computer Programming Engineers	2
Computer Maintenance Engineers	2
	21

7 SAFETY

7.1 Safety Record

Many formal in-depth studies have been performed in Canada on reactor safety. All have concluded that the Candu system has a very low probability of a serious accident. The major problem has been to determine the theoretical probability of an accident since no accident history exists to develop statistics. Various hypothetical comparisons have been made such as the probability of being killed by a nuclear plant accident is similar to being killed by a meteor, but these estimates are open to criticism.

The history to date shows that:

1. No member of the public has ever been killed or injured due to the operation of a commercial reactor.
2. There have been no lost time accidents due to radiation exposure in operation of the Candu reactor.

7.2 Accident Prevention and Mitigation

There are three main elements to prevention of accidents:

- safety and performance are priorities in design to maintain public safety and reduce down-time.
- Safety systems operating independantly with fail-safe operations and capable of handling dual failures.
- Rigorous operator education and training.

Regardless of the extent of design, safety systems and operator training, accidents will occur from equipment failure, human error or acts of God. In this case, containment of the radioactive materials is the priority. Radioactive materials produced in the reaction form 1% of the spent fuel. These products remain fused in the ceramic uranium oxide which is incased in metal tubes. The next barrier is the cooling system which, if not in place (loss of coolant accident), could result in a damage to about one-fifth of the ceramic binding and metal casings. Should this occur, the reactor building with reinforced, pre-stressed concrete walls of 1.2 meters thick could contain any released reaction products.

Finally, the exclusion zone provides an additional buffer to prevent high exposures to the public caused by any released material.