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HYDROGEN FROM REMOTE EXCESS HYDROELECTRICITY

by

Nancy Ouellette
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We accept this thesis as conforming
to the required standard

Dr. D.S. Scott, Supervisor (Department of Mechanical Engineering)

Dr. H.-H. Rogner, Supervisor (Department of Mechanical Engineering)

Dr. R. Vahldieck, Outside Member (Department of Electrical Engineering)

Dr. B.W. Glickman, External Examiner (Director, UVic Centre for Environmental Health)

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University of Victoria

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Supervisors: Dr. David Sanborn Scott and Dr. Hans-Holger Rogner

ABSTRACT

This thesis is based on a project performed under contract between IESVic and a consortium of municipal, institutional and governmental organizations in the Northwest Territories. The objective of the study is to examine the techno-economic feasibility of establishing a new hydrogen-based industry utilizing the surplus/off-peak generating capacity of the Taltson Dam and Generating Station, near Fort Smith, Northwest Territories.

After evaluating the amount and cost of hydrogen produced via water electrolysis from the excess capacity, the study investigates three potential hydrogen utilization scenarios:

- 1) merchant liquid or compressed hydrogen,
- 2) hydrogen as a chemical feedstock for the production of hydrogen peroxide,
- 3) methanol production from biomass, oxygen and hydrogen.

The following results and recommendations were presented to the NWT steering committee:

- Given favourable electricity rate, low cost electrolytic hydrogen can be produced in Fort Smith and therefore represents an opportunity to develop a local hydrogen-based industry.
- Of all options examined, hydrogen peroxide is the most promising and attractive.
- A detailed market study should be performed to clearly assess the current consumption and future growth of demand in the target pulp and paper industry market.
- If the market study proves favourable, investors have to be identified starting with existing hydrogen peroxide producers which can provide technology and experience.

Finally, in a more general context, this thesis examines the synergies, opportunities and barriers associated with hydrogen and excess hydroelectricity in remote areas and concludes with the following:

- In the long term, hydrogen as a regionally "domestic" energy currency could serve the development of "remote region" energy systems in Canada.

- Near-term direct uses of hydrogen in remote communities are precluded by the high capital cost barrier of today's hydrogen end-use technologies.
- There is an immediate need and a concurrent business development opportunity for manufacturing medium efficiency/low capital cost hydrogen end-use technologies. These technologies would serve well the development of remote regions in Canada and could also be of interest to developing countries.

Examiners:

[Redacted]

Dr. D.S. Scott, Supervisor (Department of Mechanical Engineering)

[Redacted]

Dr. H.-H. Rogner, Supervisor (Department of Mechanical Engineering)

[Redacted]

Dr. R. Vahldieck, Outside Member (Department of Electrical Engineering)

[Redacted]

Dr. B.W. Glickman, External Examiner (Director, UVic Centre for Environmental Health)

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PART I

INTRODUCTION

Chapter 1

Introduction

1.1 Objective

This thesis is based on a project performed under contract between IESVic and a consortium of municipal, institutional and governmental organizations in the Northwest Territories. The project was carried out over a period of nine months between November 1992 and August 1993, and had the following statement of purpose:

The objective of the study is to examine the techno-economic feasibility of establishing a new hydrogen-based industry utilizing the surplus/off-peak generating capacity of the Taltson Dam and Generating Station, near Fort Smith, Northwest Territories.

The study is comprised of two parts. The first part evaluates the amount and cost of hydrogen produced via water electrolysis. The second part of the study investigates three potential hydrogen utilization scenarios:

- 1) merchant liquid or compressed hydrogen,
- 2) hydrogen as a chemical feedstock for the production of hydrogen peroxide,
- 3) methanol production from biomass, oxygen and hydrogen.

This thesis presents a description of the study including analysis, results and recommendations made to the NWT project steering committee for the pursuit of the endeavour.

In addition, this thesis includes a final section supplementing the Fort Smith reports. This final section formulates general observations concerning the synergies, opportunities and barriers associated with hydrogen and excess hydroelectricity in remote areas.

1.2 Motivation: Fort Smith Opportunity

Canada's Northwest Territories provide a unique challenge to energy planners and policy makers. Both the absolute energy demand per capita and the demand pattern differ from those in more southerly regions. The uniqueness is derived from three special factors. First, the North needs more energy for heating. Second, a total population of about 55,000 spread over more than 3 million square kilometres results in very low energy density, involves great distances and makes economies of scale difficult to achieve. Third, the load and supply variations within a typical annual cycle show greater extremes than in more temperate regions.

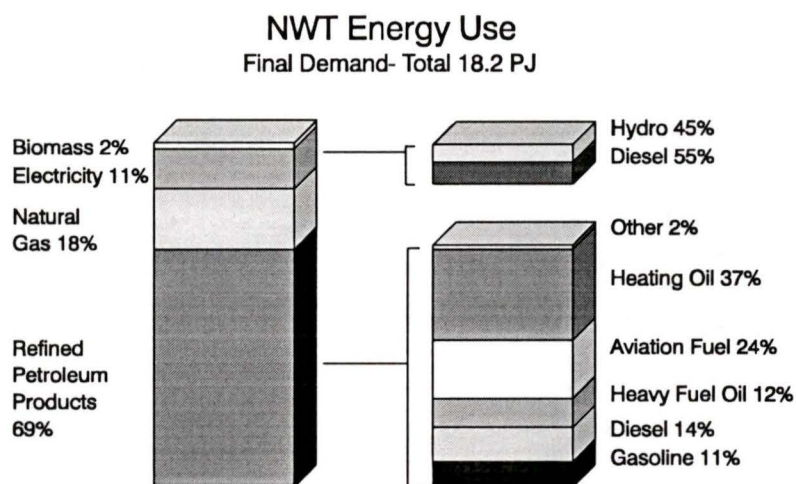
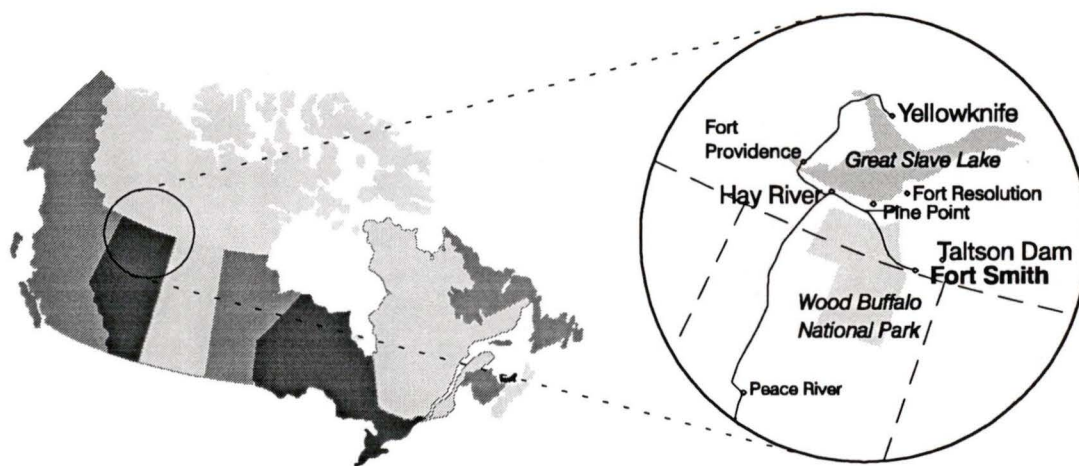


Figure 1: 1992 Northwest Territories Energy Use.[3,4]

Local energy sources vary within the Northwest Territories, with oil, natural gas, wood, hydro and wind developed to varying degrees at different locations [1]. However, most energy is used in the form of refined petroleum products (Figure 1) most of which are imported from other areas of Canada. The Government of the Northwest Territories wants to achieve lower cost of energy supply, reduce the use of fossil fuels and encourage economic development. Therefore, government policies promote both the use of local resources and the development of local industries.



Population		Road Distance	
Fort Smith	2500	Fort Smith to	
Hay River	3000	Hay River	280 km
Fort Resolution	475	Yellowknife	750 km
Yellowknife	13000	Edmonton	1230 km

Figure 2: Fort Smith Region. [3]

The surplus/off-peak capacity of the Taltson Dam and Generating Station, located in the Fort Smith area (Figure 2), presents an opportunity of this kind. Historically, the Taltson Dam provided electricity to a lead-zinc mine operating in Pine Point. Since the closure of the mine between 1987 and 1990, considerable excess capacity has been available from the Taltson Generating Station. Presently, a minimum of 8.5 MW excess hydroelectric power is available all year round. During off-peak periods, this excess capacity increases to about 15 MW. Today, the existing power grid includes the municipalities of Fort Smith, Fort Resolution and Hay River. A number of options exist for using this excess capacity, including conversion to electric heating within the grid, long distance electricity transmission to Yellowknife, establishment of new electricity-intensive industries in the Fort Smith region, or production of an energy currency¹, like hydrogen, suitable for local use or export.

¹ By analogy with a monetary currency, energy currencies are not *sources* of energy but media of energy storage, transport, and transaction. Furthermore, the energy transaction role of the energy currency implies that the nature of the currency determines the nature of the transaction that can take place. For example, a computer cannot operate on gasoline [44,45].

The Northwest Power Corporation seriously examined the possibility of transporting the excess capacity to Yellowknife through an underwater cable. However, this project proved to be uneconomical and was abandoned earlier this year.

The availability of low marginal cost electricity from surplus capacity suggests that energy intensive industries may be economically viable in the region. The town of Fort Smith's Sustainable Development Committee explored this opportunity and envisioned a hydrogen initiative, which would introduce an environmentally coherent local industry. Thereafter, a mandate was given to IESVic to investigate the feasibility of such a venture.

1.3 Overview of the Hydrogen Industry

1.3.1 Hydrogen Production

Most industrial hydrogen in the world today is produced from fossil fuel sources. Table 1 shows a breakdown of world hydrogen supply by production method, as estimated by DLR, the German Aerospace Establishment [26].

Generally, markets for large quantities of high-pressure, high-purity hydrogen are based on low-cost natural gas. Steam reforming of natural gas, commonly referred to as Steam Methane Reforming (SMR), tends to set the minimum cost of hydrogen production today.

An alternative process to SMR is partial oxidation, which is used for heavier hydrocarbons that cannot be readily reformed. The entire partial oxidation facility is typically 50% more expensive than the steam reforming process [37]. The driving force for partial oxidation is usually the availability of a hydrocarbon stream that is either less expensive or more reliable than an equivalent natural gas stream.

The gasification of coal to produce hydrogen is similar to partial oxidation, but a little more complex resulting from the need to handle solids and increased levels of impurities. Coal gasification is well known but seldom practiced for the purposes of hydrogen production. Typically, the high capital cost of gasification equipment exceeds the savings in fuel costs attributed to the lower cost of coal compared to natural gas [37].

Technology	% of Total World Hydrogen Production
Fossil Derived Hydrogen	
Steam Reforming of Naphtha, Natural Gas	38%
Partial Oxidation of Crude Oil	24%
Coal Gasification (Coke Gas)	2%
Subtotal	64%
By-Product Hydrogen	
Petro-Chemical Industry (ethylene)	18%
Petroleum Industry (gasoline)	10%
Chlor/alkali Electrolysis	1.4%
Other Chemicals	6.6%
Subtotal	36%
Water Electrolysis	< 1%
World Total	100%

Table 1: World Hydrogen Production by Technique (1987). [26]

Large quantities of hydrogen are produced as a by-product from processes in the petro-chemical industry, petroleum industry and other chemical industries. This gas is usually used as a fuel to raise process heat and steam. Sometimes it is simply vented to the atmosphere. Depending on the cost of purification, by-product hydrogen can be cost-competitive with SMR for medium size consumers. In some cases, excess hydrogen is sold on the market, either directly to the ultimate user or to an industrial gas company that adds value to the gas (by purification, compression, liquefaction or storage) before it is delivered to the consumer.

Electrolytic hydrogen accounts for less than 1% of world hydrogen production. Still, water electrolysis has been used for the commercial production of hydrogen since the turn of the century and today a large number of plants exists worldwide. The Canadian manufacturer, Electrolyser Corporation Ltd., has alone installed over 750 plants operating in more than 85 countries over the last 60 years. Water electrolysis is preferred in smaller applications, less than 5 MW, where a simple, reliable supply of hydrogen is required or where gas purity is critical. For larger plants, water electrolysis is an attractive option when the cost of electricity is competitive with natural gas or some other hydrocarbon feedstock. It is also attractive when both

hydrogen and oxygen are required by some neighbouring industrial facility, such as food processing, methanol synthesis from biomass and pulp and paper operations. Electrolytic plants up to 100 MW exist, for example, at Ryukan in Norway and at the Aswan Dam in Egypt. Both plants produce hydrogen for ammonia synthesis and both use hydroelectricity [28].

Another example of electrolytic hydrogen application is the Euro-Québec project, which plans to export liquid hydrogen produced in Québec to Europe [27]. The motivation is to exploit Québec's relatively low electricity rates. This project is currently in the feasibility stages of investigation.

1.3.2 Hydrogen Consumption

The hydrogen industry is a global, multi-billion dollar industry, with world hydrogen demands in the order of 45 million tonnes per year (1987) [26]. Most hydrogen, about 50%, is used for non-energy applications, as a commodity in the chemical and metallurgical industries (see Figure 3). One third of the world hydrogen consumption is for direct energy use, primarily for providing process heat and steam for a variety of industrial processes. Another 20% of world hydrogen demand is for indirect energy use, such as petroleum refining and synthetic fuel production.

The larger industrial uses of hydrogen include petroleum refining, ammonia production and methanol synthesis. Usually, these processes require such large quantities of hydrogen that the hydrogen is produced on-site or in an adjacent plant. This hydrogen is commonly called *captive*

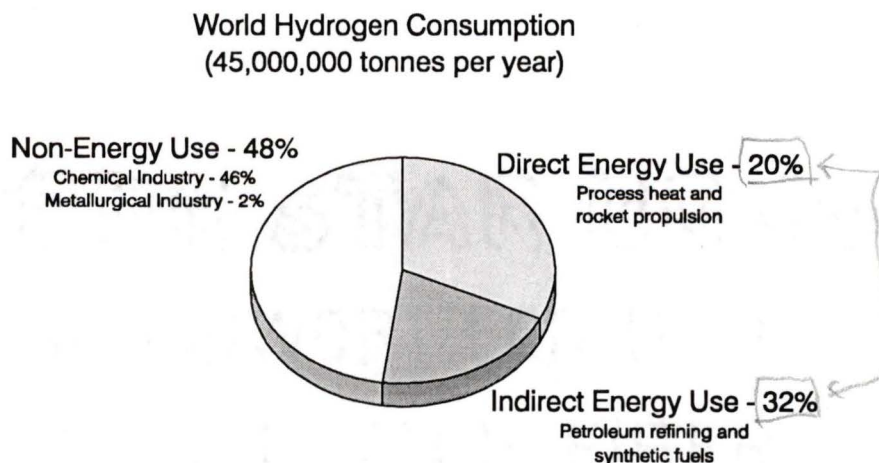


Figure 3: Breakdown of World Hydrogen Consumption in 1987. [26]

hydrogen, since it is rarely included in company sales or transported more than a few hundred metres. Captive hydrogen accounts for over 99% of world hydrogen demand.

The remaining hydrogen (less than 1%) is sold on the market to small and intermediate size consumers and is commonly referred to as *merchant hydrogen*. Current markets for merchant hydrogen include chemical processing, hydrogenation of soaps and edible oils, steel-making, glass-making, aerospace and electronics. These industries typically require relatively high purity hydrogen [8].

A large portion of merchant hydrogen is delivered by pipeline to surrounding, large volume consumers. A dedicated pipeline is the least expensive method of delivering large quantities of hydrogen over short distances, provided long term service is assured. Smaller and more distant consumers usually receive hydrogen as a compressed gas or as a cryogenic liquid. Hydrogen is delivered as a compressed gas in either leave-behind cylinders or high pressure tube trailers. If the distance is great, hydrogen is more economically delivered in bulk liquid form by tanker, trailer truck, rail car or barge. As an illustration, in 1988, 78% of the US merchant hydrogen was delivered by pipeline. Around 19% was delivered in the liquid form, and the remainder delivered as a compressed gas [26].

Canadian Perspective:

The Canadian hydrogen demand is small in comparison to the world demand. Canadian industries consume roughly 1.3 million tonnes of hydrogen per year. Figure 4 shows the breakdown of Canadian hydrogen consumption by industry.

Ammonia production accounts for almost half of the national consumption. 1,000 kg of ammonia contains about 390 kg of hydrogen or 2,035 Nm³. Ammonia is a key fertilizer in a three billion dollar domestic fertilizer industry [14].

About one third of the total Canadian hydrogen demand is consumed by petroleum refining processes. Hydrogen is required for the production of synthetic crude oil from the heavy Albertan oil sands. Hydrogen is also required for hydro-finishing, hydro-cracking, and hydro-desulfurization processes. Hydrogen requirements for petroleum refining are expected to grow due to the increasing use of heavy crudes, which require more processing, and the increasing demand for cleaner fuels.

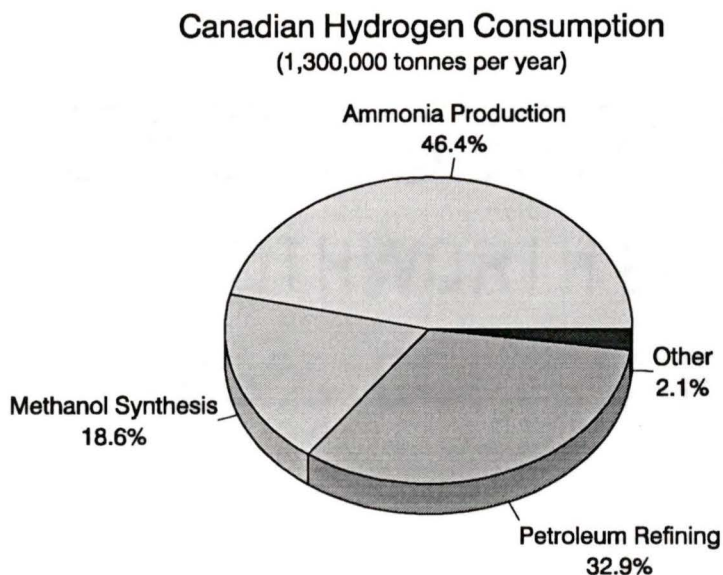


Figure 4: Breakdown of Canadian Hydrogen Demand by Industry, 1987.[14]

Methanol production accounts for about 20% of the total Canadian hydrogen consumption. Methanol is manufactured by conversion of a synthesis gas derived, in most cases, from natural gas. Canada exports methanol to both the U.S. and Japan.

Other domestic uses for hydrogen include merchant applications. Appendix B lists the major buyers of merchant hydrogen in Canada. Notable corporations include B.C. Hydro, Ontario Hydro and Hydro-Quebec, all of whom utilize hydrogen as a coolant for power station electrical generators. Other uses of Canadian merchant hydrogen include the production of wire, steel and glass, as well as the hydrogenation of oils and fats in the domestic food processing industry.

A note on Liquid Hydrogen:

Experience with liquid hydrogen began in the late 1950's with NASA's Apollo program. Today, there is a growing commercial demand for liquid hydrogen. Some consumers require liquid hydrogen, either for its high purity, as in microchip manufacturing, or for its high specific energy, as in transportation applications. Also, liquid hydrogen is preferred for delivery over long distances. The aerospace industry, which created the initial demand for large quantities of liquid hydrogen, today accounts for only 20% of liquid hydrogen demand in the U.S [38].

Location	Plant Capacity (metric tonnes/day)	Ownership
New Orleans, Louisiana	60	Air Products
Sacramento, Calif.	4.6	Air Products
Sarnia, Ont.	20	Air Products
Los Angeles, Calif.	20	Linde
Ashtabula, N.Y.	11	Linde
Niagara Falls, Ont.	30	Linde
Magog, Qué.	14	Airco
Bécancour, Qué.	10	Liquid Air

Table 2: Liquefaction Plants in North America [38]

There are nine large-scale liquid hydrogen plants currently in operation in North America, with a combined capacity of 170 tonnes per day. Table 2 shows the location, size and ownership of these liquid hydrogen production facilities.

Given the diversity of hydrogen markets, and modes of production and distribution, it becomes evident that hydrogen is not a commodity with an established market price. Hydrogen is a chemical whose cost is determined on a case-by-case basis depending on local or regional production and transportation factors.

1.4 Fort Smith Hydrogen Plant

1.4.1 Hydrogen Production

In a proposed Fort Smith facility, hydrogen is produced by water electrolysis. A large portion of electrolytic hydrogen cost is attributed to electricity. Therefore, when low electricity rates exist, electrolytic hydrogen may be cost-competitive with the market leader steam methane reforming.

Two potential by-products can be recovered from the production of electrolytic hydrogen: *oxygen* which is inherent to the reaction and *heavy water*² using some additional technology. The collateral benefits of these by-products may well enhance the prospects for electrolytic hydrogen

² Heavy water (D₂O) is used as a moderator in Canada's CANDU reactors.

production. Yet, these benefits should not be the determining factor for the project feasibility. Therefore, the study quantifies the benefits but does not include them in the economic analysis.

1.4.2 Hydrogen Utilization

Figure 5 illustrates the utilization scenarios that were considered at the preliminary stage of analysis. The hydrogen produced in Fort Smith can be exported and sold on the merchant market, used directly as a fuel, or used as a chemical feedstock for a local chemical synthesis industry. In consultation with the Steering Committee, it was decided that the most attractive strategies were merchant hydrogen and hydrogen as a feedstock for the production of hydrogen peroxide and methanol. This section addresses the rationale for this decision.

Ammonia

Large quantities of hydrogen are required for the production of ammonia. The establishment of an electrolytic hydrogen production facility in Fort Smith suggests possible synergies which may promote an ammonia production plant in the Northwest Territories. However, these synergies are outweighed by a variety of market factors. In today's market, ammonia is produced in

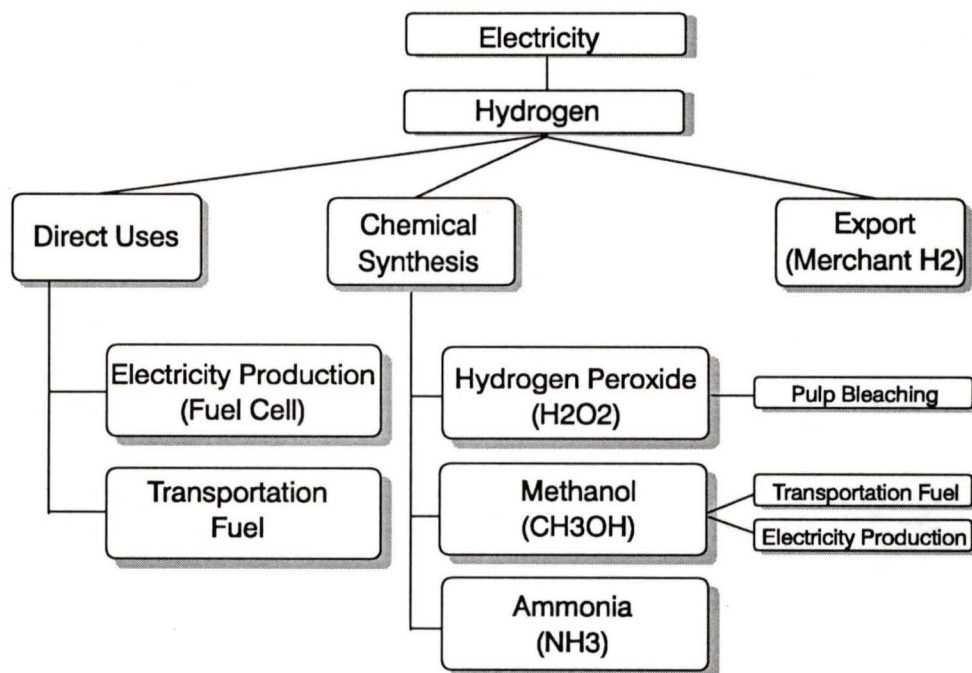


Figure 5: Hydrogen Utilization Options.

extremely large scale facilities, many times larger than the plant size allowed by the excess capacity of the Taltson Dam. For this reason, any envisioned ammonia production plant in Fort Smith could not compete with existing plants in terms of both capital cost and hydrogen production cost. Furthermore, the ammonia market is far removed from the Northwest Territories, leading to high transportation costs.

Hydrogen as a Fuel

Hydrogen used as a fuel for electricity production through fuel cell technology provides an option for electricity generation in remote communities of the Northwest Territories. Utilizing indigenous energy sources reduces energy dependence on fuel imports from outside of the territories. Nevertheless, in the short and medium term, the capital cost of fuel cell technologies remains a barrier to implementing hydrogen as a fuel for electrochemical power conversion.

Hydrogen can also be used as a transportation fuel, either with fuel cells or internal combustion engines. But hydrogen vehicles are still in the development stages, with no commercial systems on the market. The barrier of high capital cost coupled with the lack of hydrogen infrastructure outside of the Northwest Territories suggests that hydrogen transportation systems are not a realistic short-term goal for hydrogen use in Fort Smith.

Hydrogen Peroxide

Hydrogen is a significant chemical feedstock for the production of hydrogen peroxide. Moreover, there is a nearby market for hydrogen peroxide, alleviating the potential handicap of high transportation costs associated with most Northwest Territories industrial export products. Hydrogen peroxide is used as a bleaching agent in the textile and pulp and paper industries. Consequently, the pulp and paper industry of Northern Alberta and Northern B.C. constitutes the most promising market for a hydrogen peroxide production plant in Fort Smith. Although this market is presently saturated, there is a potential for increasing demand. Primarily as a substitute bleaching agent for chlorine and chlorine dioxide, environmental concerns will increase the demand for hydrogen peroxide and create the need for additional capacity.

Methanol

Biomass as the principal feedstock for methanol production has been advanced as an additional income generating activity for agriculture and/or forestry dominated rural areas. However,

conventional biomass based methanol production processes are hydrogen deficient. That is to say, the hydrogen content of the biomass is insufficient for complete conversion into methanol. Consequently, one has to add hydrogen to the process or reject some of the biomass' carbon in the form of CO₂ emissions. Most processes also require supplemental oxygen for the intermediate conversion of the biomass into a synthesis gas.

A readily available supply of hydrogen and oxygen, therefore, should improve the overall productivity of biomass derived methanol. In the case of Fort Smith, biomass is either wood chips or partially burnt residual wood from forest fires. Typical methanol markets in Fort Smith include transportation (admixed with gasoline or pure) and electricity generation. If produced competitively, local use of biomethanol produced in Fort Smith replaces imported gasoline or diesel and thus reduces overall energy costs as well as the dependence on fuel imports.

Merchant Hydrogen

Unless a local market is established, hydrogen produced in Fort Smith must be exported and sold on the merchant market. This requires the hydrogen gas to be either compressed (175 bars) or liquefied for transportation. The energy required for such a state change reduces the amount of hydrogen that can be produced by the Fort Smith facility. For the case of liquefaction, this reduction is significant.

One of the largest applications for hydrogen in today's hydrogen economy is for the refining and upgrading of heavy oils. Of particular regional interest is the hydrogen upgrading of the heavy oil sands of Northern Alberta. However, selling hydrogen produced in Fort Smith on the merchant market for such an application is not altogether promising. Petrochemical plants typically produce raw hydrogen gas using large scale on-site steam methane reforming. The additional costs of liquefying or compressing and distributing will make merchant hydrogen produced in Fort Smith too expensive to gain a market in the petrochemical industry.

Other more promising merchant markets demand relatively small quantities of *high purity* hydrogen. Examples of such markets include glass manufacturing, steel manufacturing and food processing. For these uses, the cost of hydrogen compression/liquefaction and transportation can be only a minor influence to the economic success of the venture.

1.5 Methodology

This study examines the feasibility of three hydrogen-based industries in the Fort Smith area: merchant hydrogen, hydrogen peroxide and methanol. At this pre-feasibility stage of investigation, Fort Smith's parties are interested in two questions which constitute the boundaries of the analysis:

- What level of production can be sustained from the available excess power?
- How does the end-product cost compare with relevant competitors?

The following approach is used to configure and evaluate each process examined in this study.

Technology Selection

First, a review of existing technologies is performed in order to select the most appropriate technology or process for the Fort Smith context. Short-term feasibility of the project is an important factor in this study and, therefore, the selection is limited to proven technologies.

Modeling

Each technology or process is modeled in terms of the following parameters which represent performance and cost using today's state-of-the-art technologies:

- Energy requirements per unit output
- Material requirements per unit output, including hydrogen and other chemical feedstocks
- Lifetime of the technology, in years
- Investment cost of the technology, per unit output capacity
- Variable operating cost, includes materials and energy requirements
- Fixed operating costs, includes maintenance, labour, overhead and insurance

Scenario Development

Technology models are assembled using computer simulation methods to represent the complete production plant, from the excess capacity of the Taltson Dam to the end product produced. Scenarios are developed to investigate the performance of the production plant under different

configurations. Scenario development examines the use of different portion of excess electricity used, different technologies, as well different plant sizes.

Analysis

Plant capacity

The availability of excess electric power from the Taltson Dam and Generating Station constitutes the known variable and starting point of the analysis. This excess available power varies daily and seasonally.

In determining the production capacity, components of the overall production plant are distinguished as follow:

- Hydrogen production technology vs hydrogen conversion technology
- Constant operating load technology vs variable operating load technology

Hydrogen production technology used in this analysis is capable of load following while some conversion processes require constant operating conditions. Therefore, the rate of hydrogen utilization may not follow the rate of production.

An iterative process varies the size of the components to ensure a balance of the hydrogen mass flow at the end of an annual cycle. By following the production sequentially, the model also keeps track of excess hydrogen periods in order to determine the minimum requirements of intermediate storage facility.

Also, at each point in time, an energy balance ensures that the energy requirements of all components are satisfied and are within the limits of power availability. The energy consumed by conversion processes reduces the amount of hydrogen that can be produced from the excess available power.

Life-cycle cost

This study determines the unit cost of production of each end-product on the basis of full life-cycle costs analysis. Life-cycle costs account for the total cost of ownership and operation of an asset over the asset's lifetime.

In addition to the individual cost model of each component of the production plant, two supplemental criteria are required to account for the value of money over time and the degree of utilization of the technology. These are:

- Discount Rate
- Plant factor, the fraction of the year the technology is in service

Sensitivity analysis

Sensitivity analysis examines the influence of key cost parameters on the production cost of each end-product. Parameters such as electricity rate and discount rate are varied around the base case scenario to determine how a change in their value would affect the feasibility of the project.

Principal Assumptions

Location of the Plant

The analysis is based on a production plant located in the Fort Smith area. Beyond Pine Point, the transmission line cannot support the dam's total excess capacity [122]. Therefore, Fort Smith is preferred logistically to other industrial settings, such as Hay River.

Electricity Rate

The marginal operating cost of producing the excess electricity was not provided by the Power Corporation. However, typical operating costs range between 0.1 and 0.15 cent/kWh [2]. Applying a favourable electricity rate, in order to attract an energy intensive industry, is justified by the Power Corporation since no other option exist, in a foreseeable future, to utilize the excess capacity of the Taltson Dam. The base case in this analysis assumes a cost of electricity of 1 cent/kWh.

Plant Factor

For maintenance purposes, the plant is assumed to interrupt production twice during the year for a total of 20 days, corresponding to a plant factor of 94.5%

Dollars Unit

Otherwise specified, all cost figures are given in Canadian dollars at 1993 prices and exchange rates. A real rate of interest of 8% is used as a discount rate.

PART II

HYDROGEN PRODUCTION

Chapter 2

Taltson Dam Production Profile

The Taltson hydroelectric facilities are located about 55 km North East of Fort Smith. With approximately 30 m of head, the capacity of the generating station is 21 MW. Between the early 60's and the late 80's, the years of mining operations at Pine Point, the dam was operated at full capacity all year round. With the closure of the mine, the electricity demand became considerably smaller leaving the dam underutilized.

Hourly production data at the Taltson Generating Station for 1991 were provided by the Northwest Territories Power Corporation (Hay River office). Aggregated data of daily and nightly average production are presented in Figure 6 on the following page. Unfortunately, data was incomplete for some periods of time. To assure continuity, averages preceding and following the missing periods were used to create a realistic trend in the consumption profile. The vertical axis is scaled to represent the dam capacity of 21 MW.

The area below 21 MW and above the production curve represents the amount of power unutilized in 1991. It is referred to as excess surplus and off peak capacity. Surplus capacity is the difference between the maximum capacity of the generation station (21 MW) and the maximum power actually used during the year. Off-peak excess power is the difference between low consumption periods and high consumption periods.

When operating at full capacity, the generating station can produce a total of 184 GWh during the year. In 1991, the amount generated, the area under the curve, totaled 67 GWh, leaving 117 GWh or about 63 % of the electrical resource unused.

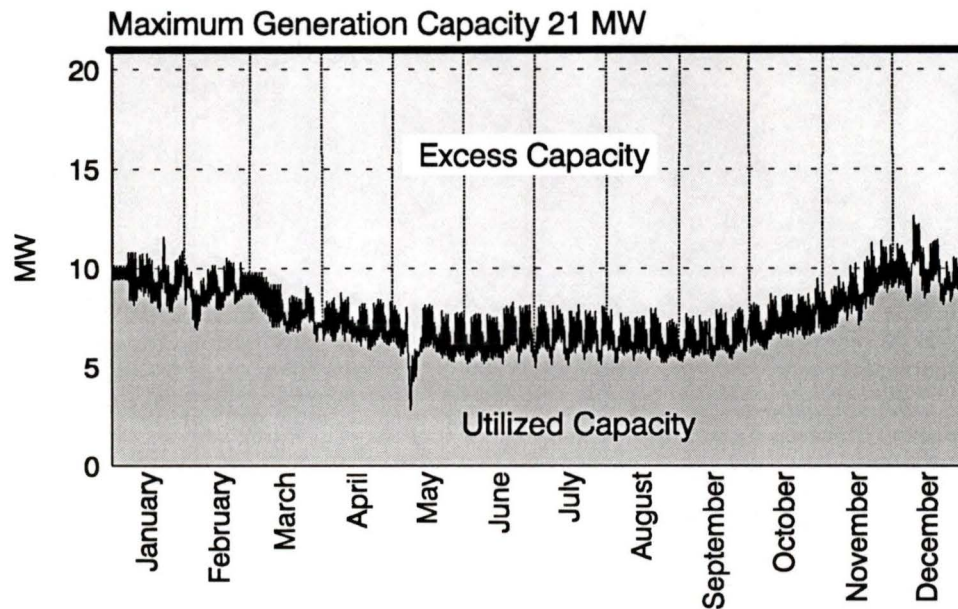


Figure 6: 1991 Day and Night Production at the Taltson Dam Generating Station

Source: Northwest Territories Power Corporation, [123]

Chapter 3

Hydrogen Production Plant

3.1 Water Electrolysis

3.1.1 The Process

When a direct current is passed through water between two electrodes, water decomposes according to the reaction $H_2O \rightarrow H_2 + \frac{1}{2}O_2$. (See Figure 7) Pure water is a poor conductor of electricity and therefore in order for this reaction to proceed, an electrolyte must be added to the water to increase the conductivity.

Water dissociates into hydrogen and hydroxyl ions (H^+ and OH^-). The positive hydrogen ions migrate toward the cathode, the negative electrode, where they are discharged by picking up electrons and forming hydrogen molecules: $2H^+ + 2e^- \rightarrow H_2$. The hydrogen molecules accumulate on the surface of the electrode until a bubble forms, breaks away and rises to the surface of the electrolyte.

A similar process but of reverse polarity occurs at the oxygen electrode, called the anode. Hydroxyl ions migrate to the electrode surface where they form oxygen gas

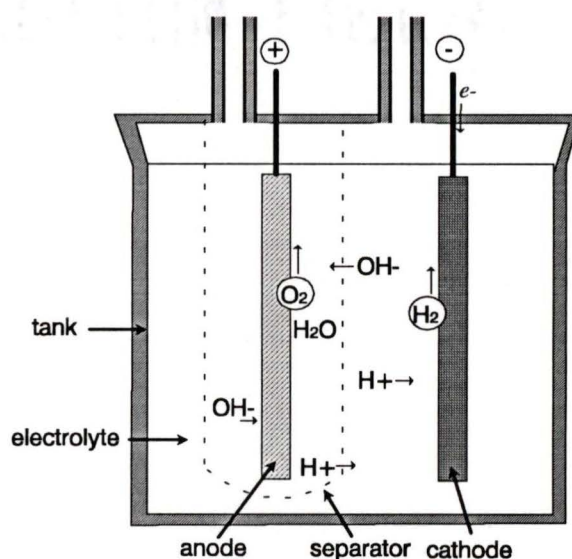


Figure 7: Electrolysis Process.

and water $4OH^- \rightarrow 2H_2O + O_2 + 4e^-$. A separator prevents the hydrogen and oxygen from mixing. All these elements form the *electrolysis cell*.

The rate of gas generation within a cell depends on the cell electrodes' surface area, that is, the area available for the reaction. It is also a function of the current sent through the electrodes usually referred to as current density, expressed in kA/m^2 of electrode area.

For the reaction to occur, a minimum voltage has to be applied.³ Operating at the minimum voltage is an ideal. In reality, because of internal resistance and other losses, the voltage applied is higher than ideal, resulting in an efficiency lower than 100%. Consequently, the energy content of the hydrogen is less than the energy content of the electricity used to produce it.

3.1.2 The Technology Options

Over the last hundred years or so, efforts have been made to improve cell efficiency and reach high current densities in order to reduce both electricity consumption and capital cost. Today's electrolysis units come in many different configurations that include: activated or porous electrodes, liquid or solid electrolyte, reaction pressure from atmospheric up to 40 atmospheres, reaction temperature from 70 °C (where water is liquid) up to 1000 °C (where it is a vapour) and more [9,22,33]. Present technology and novel concepts for advanced electrolysis can be categorized into five electrolyser families;

- conventional alkaline electrolyser,
- advanced alkaline electrolyser,
- inorganic membrane alkaline electrolyser (IME),
- solid polymer electrolyser (SPE),
- high temperature electrolyser (HTE).

Table 3 summarizes the principal design and operation characteristics of these electrolysers. IME, SPE and HTE provide a number of advantages such as higher current density, lower voltage or higher efficiency. However, these technologies are still at an early stage of development. In this study, we want to restrict ourselves to proven technologies. Consequently,

³ At 25 °C, the thermoneutral voltage is 1.47 Volts corresponding to the adiabatic and isobaric enthalpy change of the thermochemical reaction $H_2O \rightarrow H_2 + \frac{1}{2}O_2$ [19].

the selection is reduced to conventional and advanced alkaline electrolyzers. The advanced alkaline electrolyzer has already proven improved overall performance and cost leaving behind the conventional electrolyzer.

The advanced alkaline electrolyzer category includes unipolar and bipolar configurations⁴ and both are well established in the market. Bipolar electrolyzers are generally more compact and have greater potential for high temperature and high pressure electrolysis. The principal interest in high pressure electrolysis is to save on gas compression cost. On the other hand, high pressure induces higher stresses on construction materials and seals, requires a more delicate pressure balance across the gas separator and therefore reliability and security become the issues. Depending on the application, the additional cost of high pressure system may outweigh the expected cost saving in compression.

Although bipolar and unipolar technologies demonstrate comparable performance characteristics and cost, the unipolar is preferred in this application because of its ability to operate at varying load conditions. Moreover, unipolar technology is a simple design. It offers reliable operating performance over time, requires minimum peripheral equipment and is fully modular (cells connected in series to give desired capacity). Maintenance can be done on one cell at a time by using a bypass jumper, which allows the electrolyzer to operate at a very high load factor. The Electrolyzer Corporation Ltd. is a Canadian manufacturer of unipolar technology. Their most recent industrial electrolysis system, the EI-250, is used in the study.

⁴ Unipolar cells have single polarity electrodes either positive or negative as opposed to bipolar cells which have both polarity on a single electrode, positive on one side and negative on the other.

TECHNOLOGY	ALKALINE ELECTROLYSERS (unipolar and bipolar)				SOLID POLYMER ELECTROLYSER	HIGH TEMPERATURE ELECTROLYSER
	Electrolyser Inc. El-250 Cell	Conventional	Advanced	Inorganic Membrane		
TEMPERATURE(°C)	70	70-90	90-145	90-120	80-150	920-1000
PRESSURE (atm)	ambient	ambient, except Lurgi 30 atm.	up to 40 atm	up to 40 atm	up to 40 atm	up to 30 atm
CATHODE	activated	steel, stainless steel or nickel	activated Ni	NiS	porous carbon fiber paper with catalyst	Ni
ANODE	activated	nickel	activated Ni	Spinel oxide	porous titanium with catalyst	Ni-NiO or perovskite (LaNiO ₃ , LaMnO ₃ , etc.)
GAS SEPARATOR		asbestos	asbestos, teflon- K-titanate, poly- benzimidazole	polyantimonic acid membrane	multilayer expanded metal screen	None
ELECTROLYTE	25% KOH	25-35% KOH	25-40% KOH	14-15% NaOH	nafion membrane	Solid Y2O ₃ -stabilized ZrO ₂
AT NOMINAL OPERATING LEVEL						
CELL VOLTAGE (V)	1.85	1.84-2.25	1.5-3.0	1.6-1.9	1.4-2.0	1.95-1.3
CURRENT DENSITY (kA/m ²)	2.5	1.3-2.5	2.0-20	2.0-10	2.5-20	3.0-10
CELL EFFICIENCY ^a	81%	77-80%	80-90%	82-91%	85-90%	90-100%
POWER CONSUMPTION (kWh/Nm ³ H ₂)	4.4	4.3-4.9	3.8-4.3	3.6-4.0		3.5
LEVEL OF DEVELOPMENT	commercial	commercial	commercial	laboratory scale and prototype	laboratory scale and prototype	small laboratory scale

^a Efficiency is defined as the energy content of hydrogen over the energy content of electricity.

Table 3: Conventional and Advanced Electrolyser Technologies [9,22,25].

3.1.3 The Electrolyser Corporation Ltd. EI-250 Cell System

Technical characteristics

EI-250 evolved from half a century of experience with the unipolar Stuart Cell technology applied in more than 750 installations [11,34]. Key features of the EI-250 cells include improved current distribution along the electrodes, activated electrodes which allow operation at both higher current density and efficiency, H clamp electrical inter-cell connections to minimize voltage losses, and internal electrolyte circulation which eliminates problems of corrosion, pumping and blockage.

Current Rating ^a	100 000 amperes
Dimensions	2.1 m long
	1.1 m width
	1.8 m height
	6.6 tonnes
Operating Pressure	Ambient
Electrolyte Temperature	70 °C
Current Density ^a	2.5 kA/m ²
Cell Voltage ^a	1.85 Volts
Energy Efficiency ^a	81 %
Energy Consumption ^a	4.4 kWh per Nm ³ of H ₂
Capacity ^a	185 kW
Production Rate	42 Nm ³ /hr of H ₂ (3.8 kg)
	21 Nm ³ /hr of O ₂ (30 kg)

a At nominal operating level as defined in Figure 8

Table 4: EI-250 Cell Specifications [25].

The electrolyser company produces three sizes of cells having nominal current ratings of 22000, 45000 and 100000 amperes. These represent 40, 83 and 185 kW units respectively. The largest of the three is appropriate for the plant capacities involved in this case study [131]. Table 4 presents the cell specifications.

An important feature of this unipolar technology resides in the fact that the current load can be changed rapidly between 20% and 120% of nominal operating level. This is important to take advantage of variable off-peak electric power. The figure on the right shows the operating conditions within the operating limits of the cell. We can see that part load is more efficient. The analysis takes this variation into account by tracking the load state of the electrolyser over time.

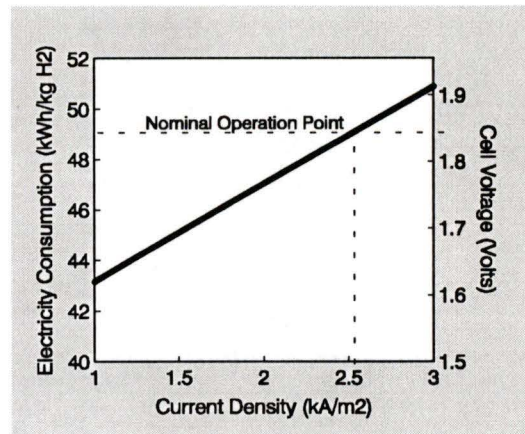


Figure 8: Influence of Current Density on Electricity Consumption and Voltage.

An appropriate number of cells connected in series will give the desired plant capacity. A set of ancillaries complete the electrolysis system as shown in Figure 9. The cells convert *direct current* and *water* to hydrogen and oxygen. Both inputs have to be conditioned before entering the cells.

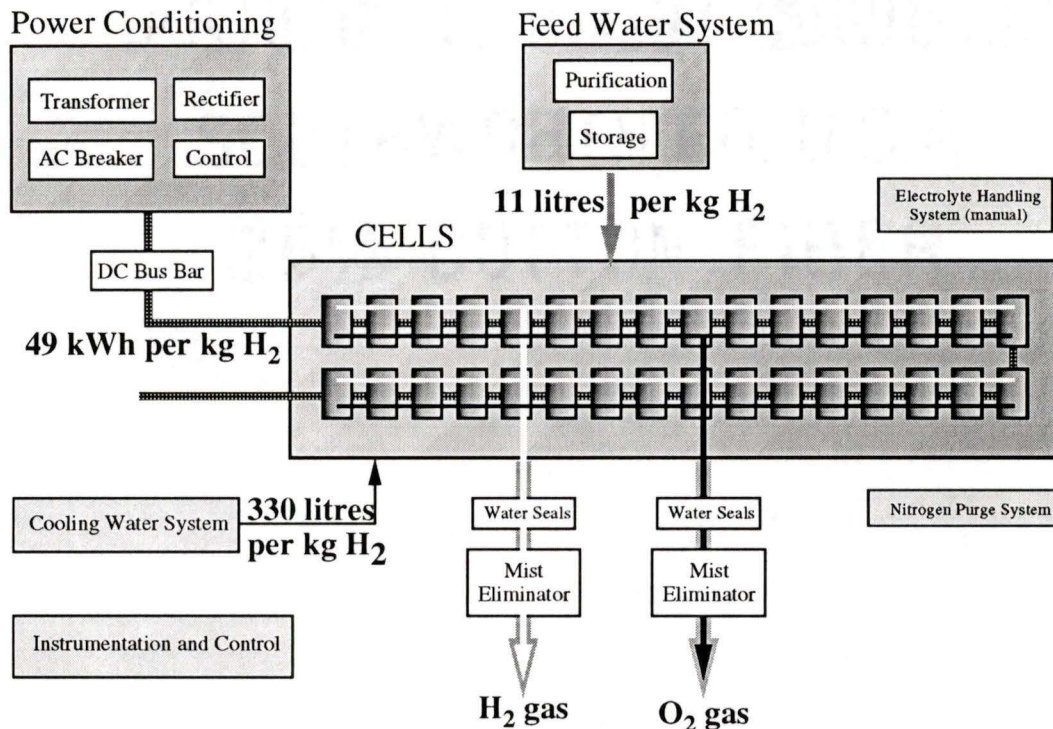


Figure 9: Electrolysis System.

The power conditioning system will convert the commercial AC power to the required DC power. Input to the AC/DC rectifier system is at a selected voltage from under 600 V to 69 kV, depending on local grid characteristics [25]. Several options are available for the specification of this system. An average efficiency of this conversion is 97% [131].

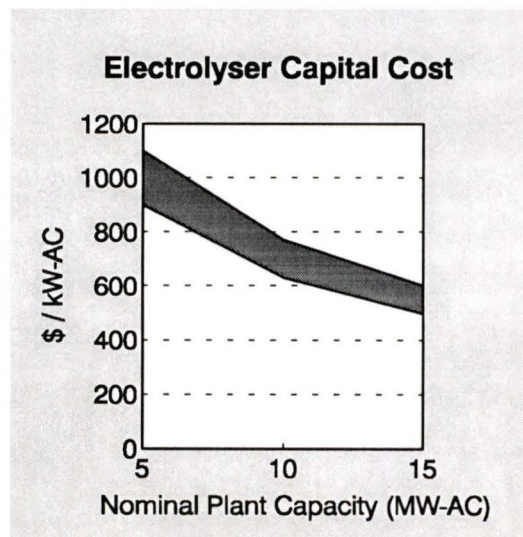
Water of less than 2 microSiemens conductivity is required. This is obtained by conventional regenerable mixed-bed ion exchange systems using acid and caustic for regeneration. A pre-purification using reverse osmosis systems can reduce the cost and handling of chemicals. The equivalent of a week's production is usually stored. Gravity brings the water to the cells.

The space needed is approximately 35 m² per MW installed nominal capacity.

Cost

The higher the production rate per cell, the better the capital investment is utilized. On the other hand, as shown before, the higher the rate of production in the cell, the less efficient the cell becomes and therefore the higher the electricity cost per unit of gas produced. The optimum level of current density is a trade-off between capital, operation and electricity cost.

The following figure shows the cost range of the electrolyser EI-250 system as supplied by the Electrolyser Corporation Ltd. The capital cost per unit of installed nominal capacity decreases as plant size increases. It is important to notice that the capital cost is given for *nominal* plant capacity. The maximum capacity is 120% of nominal. The relationship used in the analysis was taken from the middle of this range.



Operation and Maintenance Cost	7 % of Capital investment
--------------------------------	---------------------------

Lifetime	20 years
----------	----------

Capital cost includes: cells, ancillaries, power conditioning and installation.

Figure 10: Electrolyser Cost.

3.2 Heavy Water Recovery

Oxygen and heavy water⁵ constitute two potential by-products associated with the production of electrolytic hydrogen. Unlike oxygen, which is inherent to the reaction, heavy water recovery requires additional technology. The Combined Electrolysis and Catalytic Exchange - Heavy Water Process (CECE-HWP) has been developed in Canada for this and other heavy water applications. [28-31,36]

The CECE-HWP is illustrated in Figure 11. Extraction of deuterium from the electrolyser feedwater is based on the catalyzed deuterium exchange between water and hydrogen gas. Feedwater passes through an exchange tower in counterflow with electrolytic hydrogen. The feedwater becomes enriched with deuterium according to the reaction:



The deuterium concentration in the feedwater increases from top to bottom in the figure, while in the hydrogen gas stream, the deuterium concentration decreases from bottom to top.

The dehumidifier dries the hydrogen gas leaving the deuterium exchange tower and transfers to the feedwater stream condensed water vapour containing the remaining deuterium.

The scrubber between the exchange tower and the electrolysis cells serves to:

- remove entrained electrolyte from the hydrogen gas stream,
- adjust temperature and humidity of hydrogen gas to conditions prevailing in the column and
- transfer deuterium from the water vapour in the hydrogen gas stream to the liquid feedwater.

A dryer removes entrained water vapour from the product oxygen gas. This deuterium rich condensate, which may be twenty times richer in deuterium than the feedwater at the top of the column, is used as feedwater for successive stages of deuterium exchange. Only three stages are required to enrich natural water (at about 144 ppm) to reactor grade heavy water (99.8 wt%).

⁵ A heavy water molecule (D₂O) is composed of two deuterium and one oxygen atoms. Deuterium is an isotope of hydrogen, with approximately double the mass due to the presence of a neutron in the nucleus.

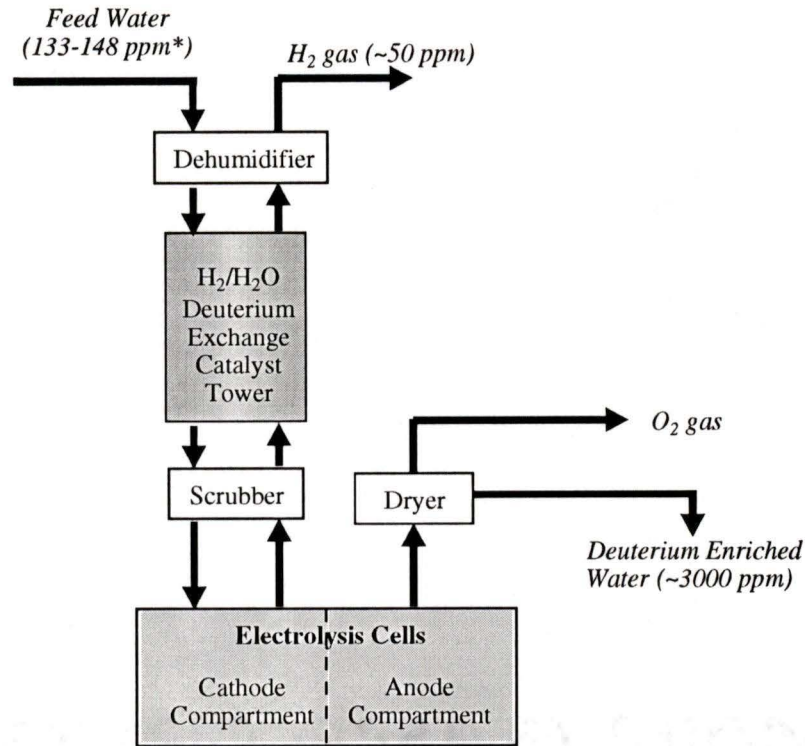


Figure 11: Combined Electrolysis and Catalytic Exchange Heavy Water Process (CECE-HWP).

*ppm: parts per million, D/(D+H)

The first, second and third stages represent approximately 95%, 4.8% and 0.2%, respectively, of the total heavy water recovery plant volume. Consequently, the first stage contributes a dominant share of the total costs to the overall project.

Characteristics

Table 5 gives a summary of the CECE-HWP characteristics used in this study as provided by the Electrolyser Corporation Ltd.

Production	0.82 g per kg H ₂
Capital cost	10% of electrolysis capital cost
O & M cost	10% of electrolysis O & M cost
Lifetime	Same as electrolyser
Energy consumption	Assumed negligible
Revenue	300 \$/kg of heavy water

Table 5: Characteristics of Heavy Water Recovery Process.

3.3 Analysis

3.3.1 Scenario Development

This section examines two different hydrogen production scenarios for utilizing all or part of the excess capacity of the Taltson Dam. (Figure 12)

The first scenario considers utilizing almost all the excess power available. Therefore, in this scenario, the amount of power available for hydrogen production varies from day to night, from weekdays to weekends, and from season to season. The electrolyser is sized to meet the peak power availability (15 MW) which occurs during the summer months. One drawback of this configuration is that part load operation of the electrolysis plant results in an under-utilization of capital investment.

The second scenario uses a level of power that minimizes the electrolyser overcapacity due to seasonal variation of power availability. The electrolyser capacity is set to the maximum power available almost all year, neglecting off-peak excess capacity (Figure 12). Certainly, Scenario 2 will produce less H_2 than Scenario 1 and for this reason may lose from economies of scale. On the other hand, Scenario 2 will gain from better utilization of capital investment.

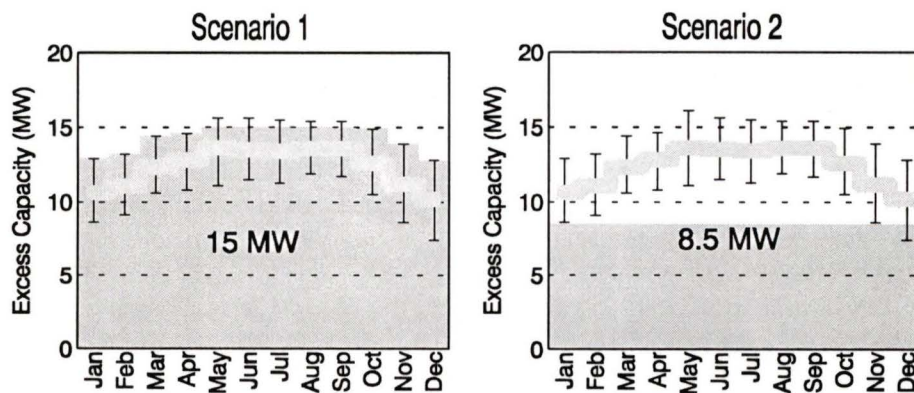


Figure 12: Hydrogen Production Scenarios.

The shaded line represents the monthly average excess capacity (1991). The vertical lines show the range of load fluctuation around the average. The shaded area represents the electricity used by the hydrogen production plant.

In Scenario 2, the electrolysis process remains an interruptible user of electricity capable of load following on a daily basis. If required, the electrolysis plant can be coupled to a short term storage facility to ensure the smooth supply of hydrogen to downstream processes.

3.3.2 Production Plant Capacity

The electrolyser operates at maximum capacity, 120% of rated nominal capacity, whenever possible. This was recommended by The Electrolyser Corporation, because of low electricity rates prevailing in this study. It maximizes use of capital investment (see section 3.1.3).

The plant is assumed to interrupt production twice during the year for a total of 20 days, corresponding to a plant factor of 94.5%. This plant factor is used throughout this study and relates primarily to the processes downstream of the electrolyser. The electrolyser does not require a complete shut down for maintenance purposes. However, continuing the hydrogen gas production while the hydrogen utilization stream is interrupted would necessitate considerable storage. This additional investment is not cost-effective as the next chapter demonstrates.

Table 6 gives the annual amount of hydrogen produced for each scenario as well as the characteristics of the respective plants.

	Scenarios	
	1	2
Hydrogen Production (tonnes per year)	2000	1365
Plant Capacity (MW)	15	8.5
Electrolyser Nominal Capacity (MW)	11.9	6.8
Number of Cells	63	36
Maximum Production (tonnes per day)	7.0	4.0
Annual Electricity Consumption (GWh)	101	70
Load Factor ⁶	80%	94.5%

Table 6: Hydrogen Production Plant Characteristics.

⁶ The load factor is defined as the actual utilization of the technology's capacity over a one year period. A load factor of less than 100% typically reflects both interrupted production and part load operation.

With capacities ranging from 4 to 7 tonnes per day, Fort Smith hydrogen production facility is at the lower end of conventional production plant sizes. In Canada, the largest producers operate steam methane reforming plants with capacity as high as 400 tonnes per day. On the other hand, water electrolysis plants exist throughout the country with capacities ranging from 0.3 to 1.1 tonnes per day.

The load factor for Scenarios 2 is determined by the two weeks the electrolyser is shut down for maintenance. The load following situation in Scenario 1 further reduces the electrolyser load factor.

It is important to remember that hydrogen production for Scenario 1 varies over time by following the availability of excess power. Therefore, this scenario requires either a concurrent consumption pattern, or intermediate storage facility.

3.3.3 Economic Analysis

The base case in this study assumes a cost of electricity of 1 cent/kWh, which will be varied later in the sensitivity analysis to evaluate its influence. Also, the capital costs quoted by manufacturers were increased by a factor of 10% to account for the inherent higher costs associated with remote installations.

Table 7 shows the cost of producing hydrogen for the two scenarios. A few points can be made:

- First, the cost of raw electrolytic hydrogen is sensitive to the electrolyser capacity. This is best illustrated by looking at the electrolyser capital cost. Scenario 1 benefits from economies of scale at 690 \$/kW compared to 919 \$/kW for Scenario 2.
- Second, the cost of raw electrolytic hydrogen is sensitive to the electrolyser load factor. In terms of \$/tonne of hydrogen, the capital component of the production cost are 418 \$/tonne and 466 \$/tonne for Scenario 1 and 2 respectively. Although Scenario 1 benefits from economies of scale, this advantage is partly offset by the electrolyser under-utilization or low load factor.

Hydrogen Production Costs

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Plant lifetime	30 years

Scenario 1

Annual production of H2	2,000 tonnes/year
Installed electric power requirements	14.9 MW

Electrolyser	63 cells
or	11,893 kW (nominal)
or	14,885 kW (max)

	Amount	Unit cost	Annual cost	Per tonne of H2
Investment	\$8,203,948	690 \$/kW (nom)	835,590	418
Average Electricity	50.7 kWh/kg	0.01 \$/kWh	1,014,274	507
Operation & Maintenance	7% of Investment		574,276	287
Total Production Costs			\$2,424,141	\$1,212

Scenario 2

Annual production of H2	1,365 tonnes/year
Installed electric power requirements	8.51 MW

Electrolyser	36 cells
or	6,796 kW (nominal)
or	8,505 kW (max)

	Amount	Unit cost	Annual cost	Per tonne of H2
Investment	\$6,246,697	919 \$/kW (nom)	636,240	466
Average Electricity	51.6 kWh/kg	0.01 \$/kWh	704,089	516
Operation & Maintenance	7% of Investment		437,269	320
Total Production Costs			\$1,777,598	\$1,302

Table 7: Hydrogen Production Costs.

In other words, it may be worthwhile to oversize the electrolyser for load following purposes. Below 15 MW, the specific capital cost of the electrolyser (\$/kW) increases rapidly as capacity decreases. Therefore, depending on the electrolyser load factor (a function of the load profile), economies of scale may prevail over underutilization of capital.

- Finally, electricity accounts for typically 40% of the raw gas cost. One can easily imagine how electricity cost will affect the production cost. This constitutes the objective of the next section.

3.3.4 Sensitivity Analysis

Figure 13 shows the influence of electricity costs on the hydrogen production costs. Raw electrolytic hydrogen production cost doubles when the electricity rate is increased from 1 to 4 cents/kWh. Electricity costs are certainly the dominating factor in an energy intensive industry like electrolytic hydrogen production and will be the key factor in the feasibility of such a venture.

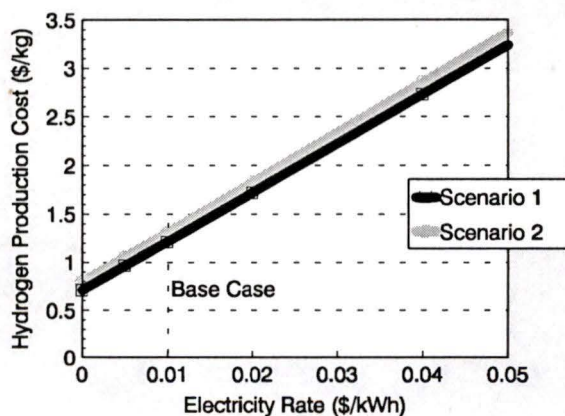


Figure 13: Influence of Electricity Rate on the Production Cost of Hydrogen.

3.3.5 By-Product Credits

Sales of heavy water and oxygen by-products can provide a credit towards the cost of hydrogen production. The market for heavy water is mainly as a moderator in Canada's CANDU reactor. Because of its high market price (\$300/kg of heavy water) and the small quantity involved (0.82g per kg of H_2), the heavy water credit is insensitive to location.

The oxygen quantity is significantly larger, 8 kg per kg H_2 or 0.5 Nm^3 per $Nm^3 H_2$. The market would have to be nearby so as to minimize transportation costs. Potential revenues from oxygen sales are set to \$50 per tonne. The direct and indirect effects of oxygen preparation for shipment are not considered in this study (e.g. oxygen liquefaction reduces the electricity available for hydrogen production.)

Table 8 shows heavy water and oxygen potential credits. Combined credits amount to about 45% of the raw gas cost with 15% attributed to heavy water and 30% to oxygen.

	Scenario 1	Scenario 2
Amount of heavy water (kg/year)	1640	1120
Amount of oxygen (tonnes/year)	19390	20830
Hydrogen production cost (\$/tonne)	1212	1302
Heavy water credits (\$/tonne H_2)	181	173
Oxygen credits (\$/tonne H_2)	400	400

Table 8: Oxygen and Heavy Water Credits.

3.4 Concluding Comments

The first part of this study reported a techno-economic analysis of producing electrolytic hydrogen in the Fort Smith region. Depending on the quantity of excess generating capacity utilized by the process, a maximum of 2000 tonnes per year of hydrogen can be produced. A capacity of 2000 tonnes/year is small compared to major North American production plants which are based on steam reforming of natural gas.

Figure 14 compares the cost of producing raw hydrogen gas at a plant in Fort Smith to the cost associated with steam methane reforming (SMR). Depending on the price of the excess electricity, electrolytic hydrogen produced at the Taltson Dam can be cost competitive with larger scale steam methane reforming plants. The potential for relatively low cost hydrogen production in Fort Smith suggests that there is an opportunity for developing local industry based on this raw hydrogen gas.

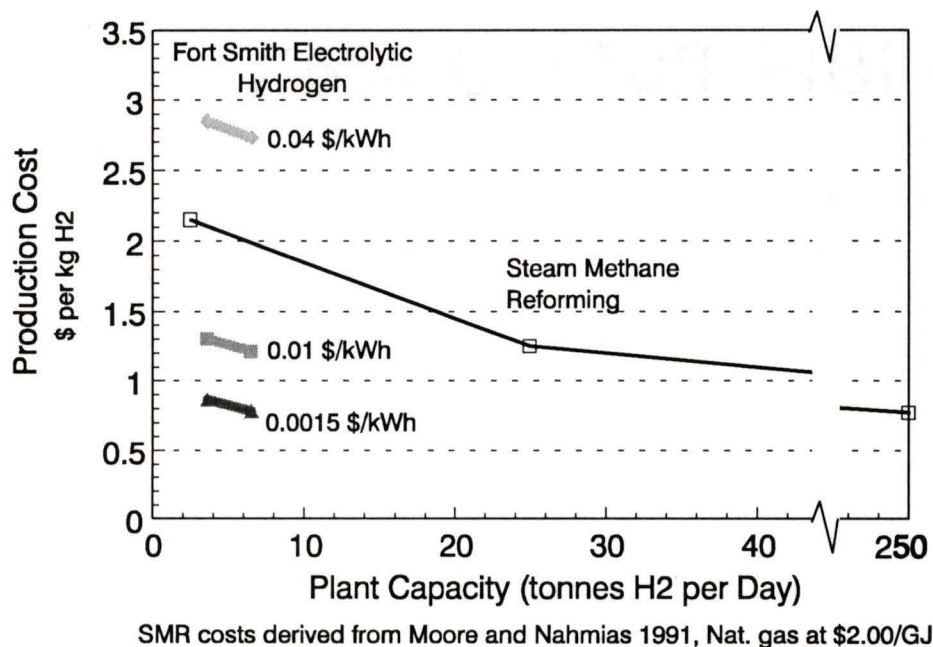


Figure 14: Comparison of Electrolytic Hydrogen in Fort Smith with Hydrogen Produced from Steam Methane Reforming (SMR).

PART III

HYDROGEN UTILIZATION

Chapter 4

Merchant Hydrogen

Unless a local market is established, hydrogen produced in Fort Smith must be exported and sold on the merchant market. This requires the hydrogen gas to be either compressed or liquefied for transportation.

Figure 15 describes the hydrogen production plant layout and its possible components. Following the electrolysis, the hydrogen gas stream goes through a purification system where water, oxygen and other residual chemicals from the reaction are removed. Then, the purified hydrogen enters the state change processes.

Liquefaction: variable load operation is not recommended for hydrogen liquefaction due to the long lead time necessary to reach liquefaction temperature. Therefore, for full utilization of excess power available, the varying rate of gas production may not track the constant rate of liquefaction and intermediate storage will be necessary.

Compression: the compressed hydrogen could be either stored or sent through a pipeline. The pipeline option is not included in this part of the study because it depends on the actual location of hydrogen utilization.

Storage: Each plant is equipped with sufficient storage facility to carry the equivalent of one week of average production.

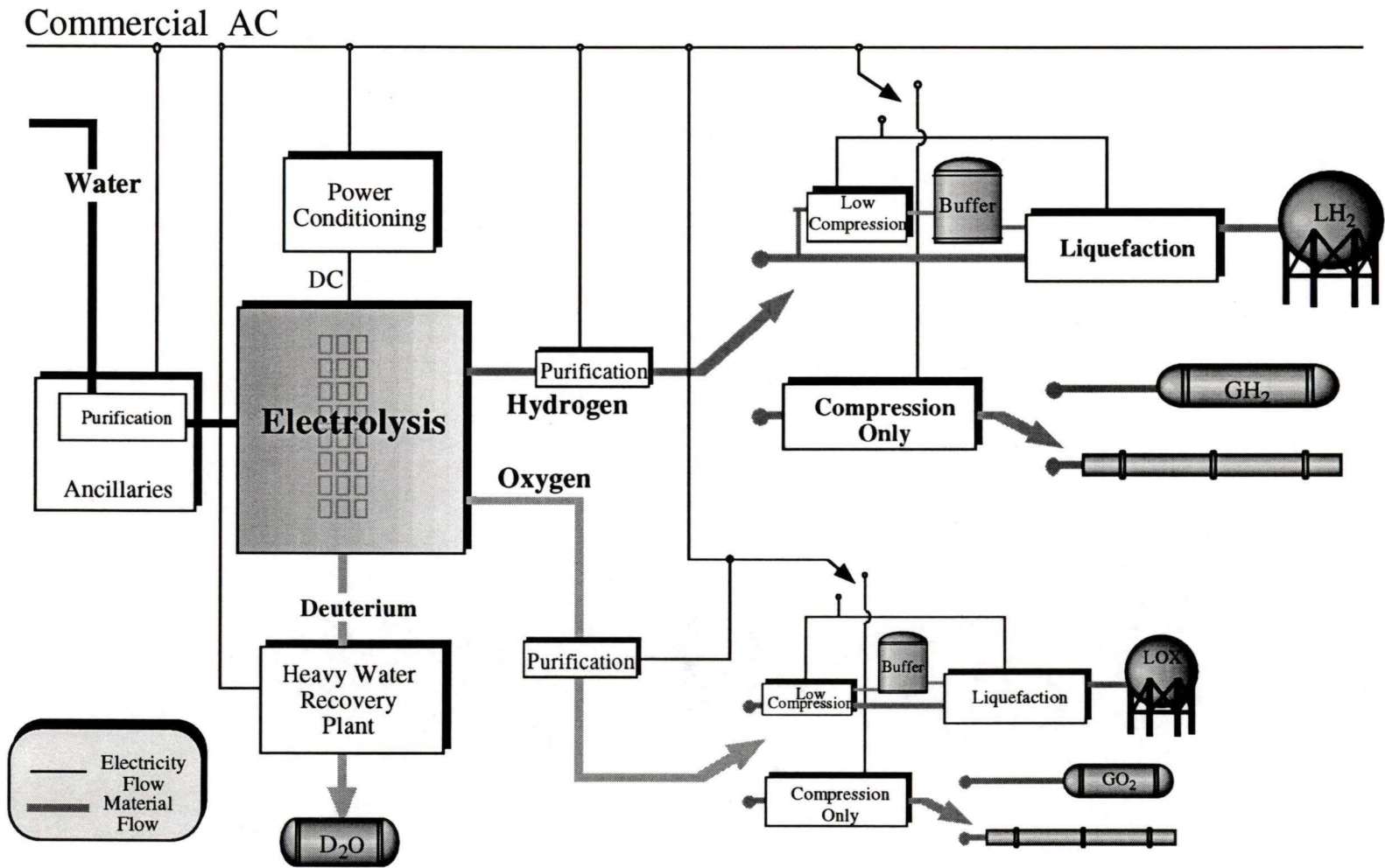


Figure 15: Merchant Hydrogen Plant Layout

4.1 Hydrogen Compression

Because of its low molecular weight, hydrogen is normally compressed in positive displacement piston compressors called reciprocating compressors [39].

The factor by which the pressure is increased from the inlet to the outlet of a compressor cylinder is referred to as pressure ratio. The pressure ratio provided by a single cylinder is limited by the discharge temperature of the gas. To obtain high pressure at increased efficiency, multiple cylinders are connected in series separated by cooling systems. This arrangement is referred to as a multistage compressor.

Table 11 presents some characteristics of compressors for two different discharge pressures. Inlet conditions are assumed to be atmospheric, 1 atm and 20°C. The compressor used for low pressure buffer storage will be capable of a discharge pressure of 35 bars. The high pressure storage requires compression to 175 bars.

Final Pressure (bar)	Minimum isothermal work ^a (kW/kg H ₂ per hour)	Number of Stages ^b	isothermal efficiency ^c	Actual work (kW/kg H ₂ per hour)
35	1.19	3	60%	1.98
175	1.76	5	60%	2.93

^a From 20 °C, 1 atm.

^b As suggested by manufacturers [102,125,127]

^c [13], includes motor drive efficiency

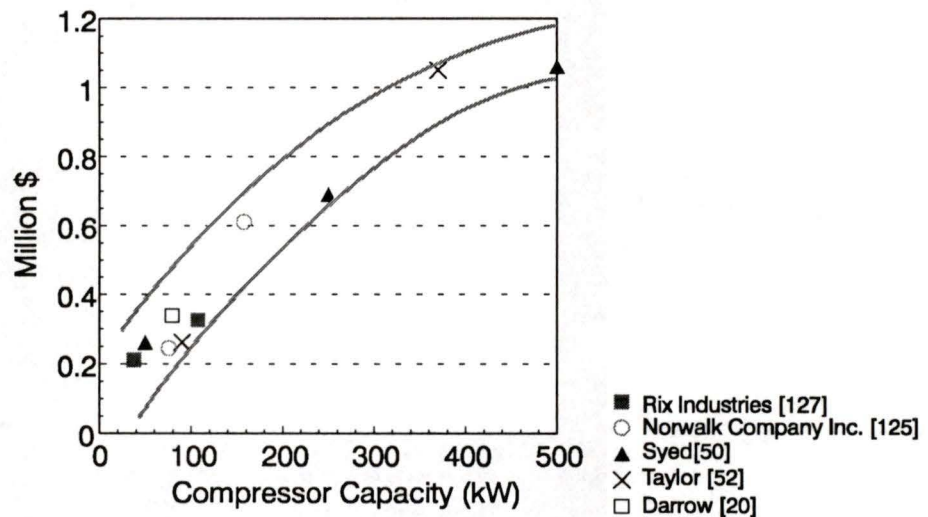
Table 9: Compressor Characteristics

For a given pressure, the compressor capacity is determined by the gas flow rate in kg/hour, Nm³/min (normal cubic metre per minute) or often used scfm (standard cubic feet per minute). For large flows, compressors can be installed in parallel.

Reciprocating compressors are available with oil lubricated pistons, non-lubricated pistons or solid lubricated pistons. Because of the design restrictions, non-lubricated piston compressors have higher power consumption. On the other hand, this design provides oil free gas so downstream heat exchangers are not fouled.

Compressors with oil pistons have the lowest power, capital cost, and maintenance cost. However, the compressed gas must be filtered to remove any contained oil and passed through adsorbers to remove any vapour.

Figure 20 shows the capital cost of hydrogen reciprocating compressors as a function of capacity. This relationship is derived from data obtained from manufacturers or found in the literature. The cost is for non-lubricated compressors or else includes purification system. It also includes installation and motor drive.



Operation and Maintenance	15% of capital investment
Lifetime	10 years

Figure 16: Compressor Cost

Include installation, assumed 30% if not specified.

Assumed 50% of capital for purification system when not included

4.2 Hydrogen Liquefaction

For water, the transition between gaseous and liquid phases occurs at a temperature of 100 °C (at atmospheric pressure). For hydrogen, this transition happens only at 20 K or -253 °C. Such supercold fluid is referred to as *cryogenic* fluid. Table 10 presents some examples.

	Liquefaction Temperature K (1 atm)	Minimum Liquefaction Energy Requirement	
		kWh/kg	kWh/L
Helium	4.2	1.89	0.236
Hydrogen	20.4	3.97	0.281
Nitrogen	77.4	0.21	0.173
Oxygen	90.2	0.92	0.195

$\Delta 1^\circ\text{C} = \Delta 1\text{ K}$
 $0^\circ\text{C} = 273\text{ K}$

Table 10: Selected Cryogenics Liquids

The conventional method of liquefying hydrogen is the Claude Cycle [38]. This cycle (simplified in Figure 17) combines stages of gas compression, cooling through heat exchangers, expansion through turbines and finally liquefaction through a valve. The cooling fluid can be hydrogen itself going through a Claude cycle as well. Another option is to use liquid nitrogen precooling (see Table 10). This option offers great advantages by improving the overall efficiency as well as the capital investment since the weight of nitrogen allows for the use of more efficient and less expensive centrifugal compressors and turbines. The nitrogen precooled Claude cycle is considered the standard cycle today for large-scale commercial liquid hydrogen plants (>4.5 tonnes per day). This cycle, however, has the disadvantage of being expensive for lower capacity.

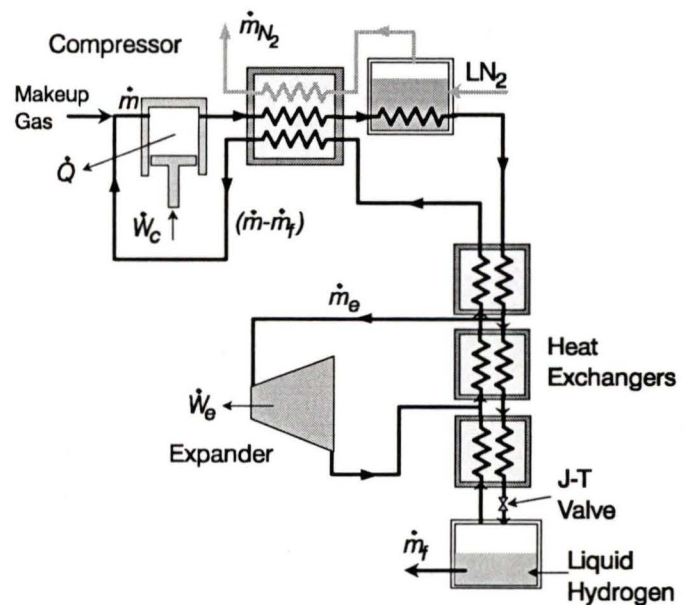


Figure 17: Nitrogen-Precooled Claude Cycle

An alternative cycle, especially interesting for small scale plants, is hydrogen liquefaction using an auxiliary helium gas refrigerator [5]. As shown in Table 10, at temperature below liquid hydrogen, helium is still a gas. Therefore, it can be refrigerated (not liquefied) in its own cycle and used to condense hydrogen at a relatively low pressure through a series of heat exchangers (see Figure 18). Again liquid nitrogen can be used to precool the helium as well as the hydrogen.

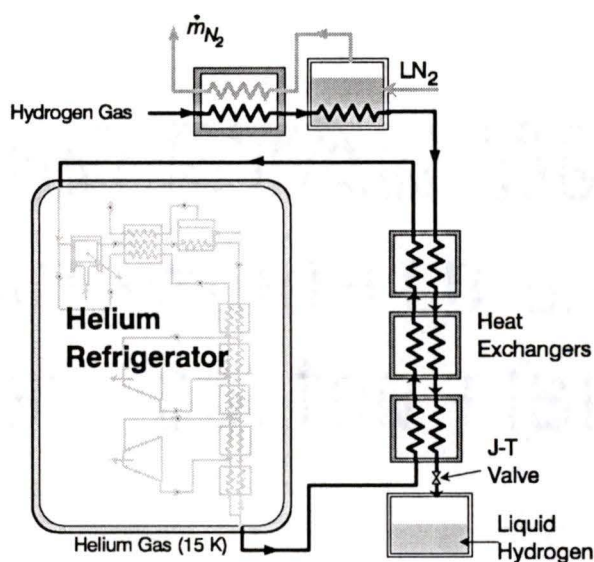


Figure 18: Helium-Gas-Refrigerated Hydrogen Liquefaction Cycle

Helium refrigerators are readily available for small scale operations and can be scaled-up to appropriate size. At least two companies in the United States have experience in designing helium-gas-refrigerated hydrogen-liquefaction system. They are Process System International (formerly Koch Cryogenics) in Massachusetts and Lotepro in New York State.

All impurities, except helium, will freeze in the liquid hydrogen lines and obstruct the circuit. Therefore, hydrogen must be 99.999% pure before entering the process [38]. Electrolysis offers a great advantage over fossil fuel derived hydrogen because of the high purity of the feed gas produced.

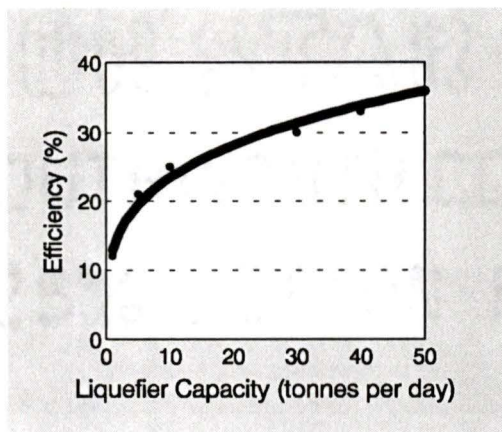


Figure 19: Conventional Liquefier
Efficiency as a Function of Size.

Includes the nitrogen precooling efficiency.

Sources: [7,43]

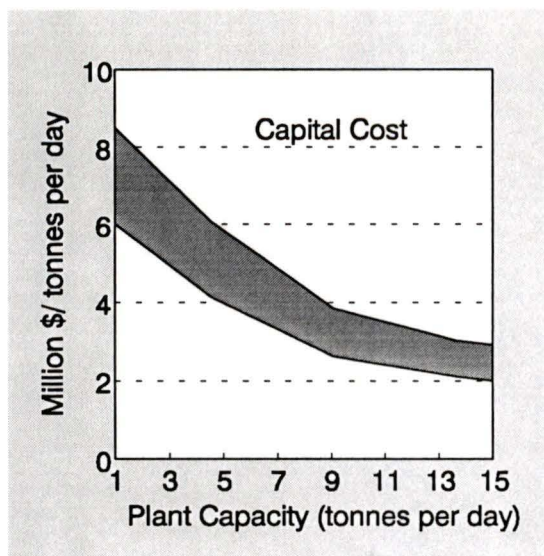
An important consideration specific to hydrogen liquefaction is the existence of two hydrogen molecule states: ortho and para. At the liquid temperature, almost all the ortho molecules, which constitute 75% of the gas at room temperature, will convert to para. By doing so, they release enough heat to transform much of the liquid back to gas. This reaction can be accelerated using a catalyst and the heat extracted during the liquefaction process.

The minimum energy to cool 1 kg of gaseous normal hydrogen from 300K, 1 atm., to liquid para hydrogen at 20K, 1 atm., is 3.97 kWh. The actual amount used in real process depends on the plant capacity. Figure 19 shows the efficiency of conventional processes as a function of the plant size.

The electricity required to produce liquid nitrogen is embedded in the overall plant efficiency. Nitrogen for precooling can be provided by an adjacent air separation plant.

<i>Air Composition</i>	
<i>Nitrogen</i>	78%
<i>Oxygen</i>	20%
<i>Others</i>	2%

Finally, the cost of a liquefaction plant is also a function of the plant capacity. Nahmias from Air Products and Chemicals Inc. recently developed cost estimates as a function of plant capacity for liquefaction plant greater than 4.5 tonnes per day. Nahmias' data and data provided by Process System International were used to develop the following cost figures.



Operation and Maintenance Cost	8 % of Capital Investment
Lifetime	20 years

Figure 20: Liquefaction Plant Cost.

Capital Cost includes installation, hydrogen storage and liquid nitrogen supply equipment (air separation). Sources: [38,43,126]

4.3 Hydrogen Storage

A variety of storage *methods* exist for hydrogen [10,24,40,53]. These include:

- Gas, low or high pressure, in pressure vessels or underground
- Liquid
- Slush
- Metal hydride
- Cryoadsorption
- Others: zeolite, glass microspheres

This study considers only the well developed and commercialized methods used today. These are pressurized gas and liquid storage.

According to their application, storage systems can be divided into distinct *categories* [53]:

- Stationary large storage system as for seasonal storage or at one end of a pipeline,
- Stationary small storage system found usually at the end-user site or used for cushion gas by a producer,
- Mobile bulk storage systems for transportation and distribution,
- Mobile fuel reservoir used in vehicles.

The emergence of U.S. space programs in the 40's initiated the era of large volume storage, handling and transport of liquid hydrogen. The technology is well developed and commercialized. As mentioned before, liquid hydrogen is at -253°C , therefore the tank or dewar has to be designed to minimize heat infiltration from the surroundings. The tank is super insulated and the overall surface area is minimized. Consequently, large liquid hydrogen dewars are usually of spherical shape. To give a feeling for size, the Becancour liquefaction plant, in Québec, is equipped with a dewar of 70 tonnes capacity (7 times their daily production capacity) which corresponds to a volume of 1000 m^3 [118]. Despite good insulation, some liquid evaporates. The rate of evaporation is less than 0.1% per day [53]. This gas is recirculated in the system and reliquefied.

Gaseous hydrogen can be shipped by means of tube-trailers. Usually, a trailer consists of nine high pressure cylinders mounted on a chassis equipped with piping and valves. Each cylinder is 61 cm (24 in.) in diameter and as long as 12 m (40 ft). The gas is stored at a pressure around 175 bars (2500 psi). One tube holds 2.6 m^3 equivalent of liquid water so about 420 Nm^3 (37.8 kg) of hydrogen. The system weighs about 27 tonnes (60000 lbs) full [107,133]. Consequently, the payload ratio (mass of hydrogen over total mass) is 1.3%.

In a liquid hydrogen plant, a small buffer tank can be included to account for gas flow fluctuation and recirculated gas throughout the processes. It is a flat bottom tank in which gas is maintained at a pressure just above atmospheric pressure. Bécancour has a 2300 m^3 buffer tank.

Finally, stationary large storage systems can take different forms depending on the amount of gas involved. Underground storage is by far the most economical. The problem of course is availability of site. There are four underground formations in which gas can be stored [52].

- Depleted oil or gas field
- Aquifers
- Excavated rock caverns
- Solution mined salt caverns

The investigation for the presence of appropriate type, size and shape of such formations in the Fort Smith area was beyond the scope of this study. Therefore this option is not considered. However, if it is suspected to be an option, it should be investigated.

Pressure Range	Tank Volume	Cost \$/kg of H ₂ stored ^a	Shape	Ref.
Ambient	14 000 m ³	665	N/A	Taylor [52]
	2800 m ³	715	N/A	Taylor [52]
12 bars	up to 10000 m ³	775	Spherical Vessel	Carpetis [18]
	150 m ³	650	Cylindrical Vessel	Bowers [103]
35 bars	1000 m ³	N/A	Spherical	Horton CBI [116]
	100 m ³	850	Cylindrical Vessel	Horton CBI [116]
40 bars	100 m ³	600	N/A	Carpetis [18]
65 bars	3.3 m ³	425	Reconditioned Cylinder	Fiba [113]
			Reinforced Cylinder	Carpetis [18]
150 bars	10 m ³	570	Cylinder	CP Ind. [107]
175 bars	2.6 m ³	550		West. Sales [133]

^a Includes installation, 30% of capital was used for installation when not accounted for.

Table 11: Examples of Pressure Vessel Storage

The only remaining H₂ storage option is above ground pressure vessels. These vessels operate in a large variety of working pressure and volume. In many cases, they are custom designed. Therefore, a large number of possibilities exist. Table 11 gives some of the combinations of pressure and volume found in the literature or obtained from manufacturers. Carpetis has done a lot of research on hydrogen storage [16-18,53] and concluded that the installed cost of pressure vessels varies between \$450 and \$850 per kg of H₂ stored. Although most of his data has been gathered at the beginning of the 80's, cost figures shown in Table 11 are in agreement with his evaluation.

Cost Modelling

As will be seen in the analysis, the cost of large stationary storage is critical. For this reason, we use the lowest end of the cost range found for pressure

	Cost \$/kg H ₂	Operation & Maintenance	Lifetime
Seasonal Storage	450	2%	15
High Pressure Tube (175 bars)	550	3%	10

Table 12: Cost Characteristics of Hydrogen Storage

vessels. This cost is shown in Table 12 along with the cost for the high pressure compressed hydrogen storage. The capital cost of the liquid hydrogen tank as well as the small buffer tank are included in the liquefier capital cost.

4.4 Analysis

4.4.1 Scenario Development

This section examines the same two scenarios discussed in Chapter 3 utilizing all or part of the excess capacity of the Taltson Dam (Figure 21). In this case, however, the amount of electricity available serves the overall production plant electricity needs; including both hydrogen production and conversion processes.

The first scenario considers utilizing almost all the excess power available which varies over time. As mentioned before, it is possible for the electrolyser and compressor to operate at varying load, but not for a liquefier. Therefore, the latter is set to operate at constant load. For the production of liquid hydrogen, the components are sized so that the amount of hydrogen produced in excess by the electrolyser during periods of peak power availability can compensate for the periods when the electrolyser production does not meet the liquefier requirements. The excess hydrogen is stored in a buffer tank. The electricity load profile is such that the storage charging/discharging cycle is annual. Hydrogen is constantly produced in excess during the summer. During the winter, that excess is drawn upon to ensure a constant liquefier load. To evaluate the size of storage requirements, hydrogen production was tracked by daily and nightly averages in order to determine the largest amount accumulated over time.

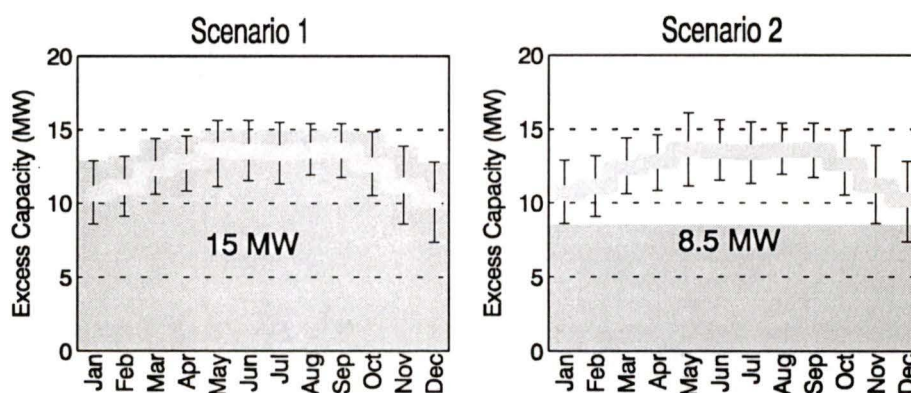


Figure 21: Merchant Hydrogen Production Scenarios

The shaded line represents the monthly average excess capacity (1991). The vertical lines show the range of load fluctuation around the average. The shaded area represents the electricity used by the hydrogen production plant.

One drawback foreseen in Scenario 1 concerns the required volume of buffer storage for the case of liquid hydrogen production which may result in high capital investment.

The second scenario uses a level of power that minimizes the seasonal mismatch of electrolyser-liquefier capacity. The plant capacity is set to the maximum power available almost all year, neglecting off-peak excess capacity (Figure 21). The electrolyser and liquefier are sized to operate in parallel. The gas produced is liquefied immediately eliminating the need for large seasonal storage in the case of liquefied hydrogen. Certainly, Scenario 2 will produce less H_2 than Scenario 1 and for this reason will benefit less from the economies of scale. On the other hand, Scenario 2 will gain from better utilization of capital and reduced storage requirements.

4.4.2 Production Plant Capacity

The electrolyser operating characteristics are the same than those described in the previous chapter. For maintenance purposes, the plant is assumed to interrupt production twice during the year for a total of 20 days, corresponding to a plant factor of 94.5%. This is representative of the liquefaction plant in Bécancour, which closes down twice a year for about a week.

Table 13 gives a description of the respective plants.

The annual production of liquid hydrogen varies between 1315 tonnes per year for Scenario 1 and 895 tonnes per year for Scenario 2. To put this production rate into perspective, the liquid hydrogen production plant at Bécancour, produces about 3500 tonnes per year. For the case of compressed hydrogen, annual production varies between 1890 and 1290 tonnes per year for Scenarios 1 and 2, respectively. As expected, the quantities of compressed hydrogen produced consistently exceed those for liquid hydrogen. This is due to the high electricity demand for hydrogen liquefaction. Table 13 shows that the electricity consumption for liquefaction constitutes 35% of the total consumption of the plant or about 50% the consumption of the electrolyser. In contrast, the compression process consumes only between 5% and 6% of the total energy.

The load factor of the electrolyser in Scenario 1, for both liquefied (72%) and compressed hydrogen (78%), is lower than the load factor calculated in Chapter 3 (80%) for the production of raw hydrogen gas. The energy required for hydrogen compression or liquefaction reduces the allowed capacity of the electrolyser. A smaller electrolyser, following the same load profile of

Scenarios	Liquefied		Compressed	
	1	2	1	2
Total Plant				
Hydrogen Production (tonnes per year)	1315	895	1890	1290
Plant Capacity (MW)	15	8.5	15	8.5
Annual Electricity Consumption (GWh)	103	71	103	71
Electrolyser				
Maximum Capacity (tonnes per day)	5.0	2.6	6.6	3.8
Maximum Capacity (MW)	10.7	5.7	14.1	8.0
Number of Cells	45	24	60	34
Load Factor	72%	94.5%	78%	94.5%
Annual Energy Consumption (GWh)	68	47	96	66
Liquefier				
Capacity (tonnes per day)	3.8	2.6		
Capacity (MW)	4.2	2.8		
Annual Energy Consumption (GWh)	35	24		
Compressor				
Capacity (kW)	112		921	522
Annual Energy Consumption (GWh)	.28		6.1	3.7
Gas Storage				
Seasonal (m ³ at 35 bars)	29,500			
Seasonal (tonnes)	83.6			
Tubes (7 Day Storage, m ³ at 175 bars)			3000	2000

Table 13: Merchant Hydrogen Production Plant Characteristics

the Taltson Dam, is more strongly affected by part load operation, and consequently exhibits a lower load factor.

Finally, two points are important with regard to seasonal storage for the production of hydrogen according to Scenario 1.

- First, the production of liquid hydrogen requires considerable seasonal storage, almost 30,000 m³ when compressed at 35 bars. Even compressed to a pressure of 175 bars, the volume required would still be important; 6400 m³, equivalent to a 19 m side cube.
- Second, the production of compressed hydrogen follows the availability of excess power and therefore requires a compatible consumption pattern. Otherwise, the requirement for intermediate or seasonal storage will also apply here.

4.4.3 Economic Analysis

Figure 22 illustrates the production cost of liquefied and compressed hydrogen for each scenario. The cost is broken down to show the influence of individual plant components. Tables 14 and 15 on the following pages detail the production cost calculations.

- Seasonal storage immediately captures the attention. It basically doubles the production cost of hydrogen and makes the liquefied hydrogen scenario with load following impractical. Therefore, for liquid hydrogen production, Scenario 2 is the preferred scenario.
- The total final cost of hydrogen may suggest that compressed hydrogen is a preferred option over liquefied hydrogen as a form for shipment, since the costs per kg are lower in both scenarios. However, a proper comparison is not possible without accounting for the actual

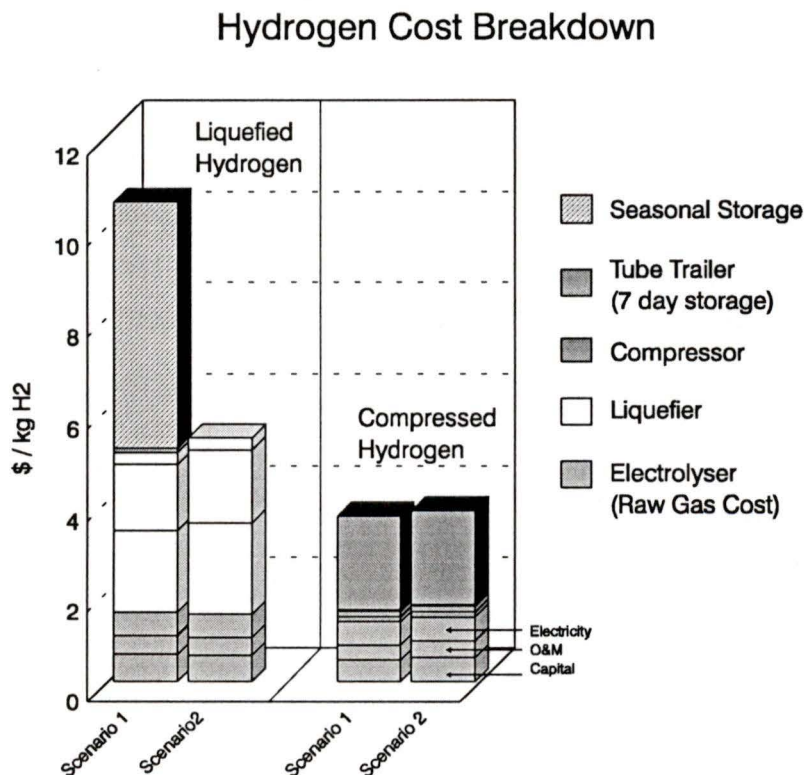


Figure 22: Breakdown of Hydrogen Cost.

Components are differentiated by their shading. The main components (electrolyser, liquefier and compressor) are broken down further into subsections for capital (bottom), operation and maintenance (middle) and electricity cost (top).

Merchant Hydrogen Production Costs Liquid Hydrogen

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Lifetime	varies for each technology

Scenario 1

Installed electric power requirements	15,049 kW
Annual Production of H2	1,314 tonnes/year

	Size	Size kW (nom)	Annual Energy GWh
Electrolyser	45 cells	8,495	67.5
Liquefier	3.81 tonnes/d	4,200	34.8
Buffer Compressor	333 Max cfm	112	0.3
Buffer Tank	29,543 m3 (at 35 bars)		

	Capital Total	Capital per year	O & M per year	Electricity per year	Total per year	\$/kg H2
Electrolyser	7,874,792	802,065	551,235	674,762	2,028,063	1.54
Liquefier	23,443,350	2,387,757	1,875,468	347,772	4,610,997	3.51
Buffer Compressor	466,652	69,545	69,998	3,467	143,009	0.11
Buffer Tank	41,451,686	6,177,524	829,034		7,006,557	5.33
Total	73,236,480	9,436,890	3,325,735	1,026,001	13,788,627	10.49

Scenario 2

Installed electric power requirements	8,554 kW
Annual Production of H2	894 tonnes/year

	Size	Size kW (nom)	Annual Energy GWh
Electrolyser	24 cells	4,455	47.1
Liquefier	2.59 tonnes/d	2,858	23.7

	Capital Total	Capital per year	O & M per year	Electricity per year	Total per year	\$/kg H2
Electrolyser	5,020,968	511,397	351,468	471,313	1,334,178	1.49
Liquefier	17,688,320	1,801,594	1,415,066	236,667	3,453,327	3.86
Total	22,709,288	2,312,991	1,766,533	707,980	4,787,504	5.35

Table 14: Cost of Liquefied Merchant Hydrogen

Merchant Hydrogen Production Costs Compressed Hydrogen

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Lifetime	varies for each technology

Scenario 1

Installed electric power requirements	15,000 kW
Annual Production of H2	1,892 tonnes/year

	Size	Size kW (nom)	Annual Energy GWh
Electrolyser	60 cells	11,332	95.9
High P Compressor	1,932 Max cfm	921	7.0
High P Tank (7 days)	2,939 m3 (at 175 bars)		

	Capital Total	Capital per year	O & M per year	Electricity per year	Total per year	\$/kg h2
Electrolyser	8,912,130	907,720	623,849	958,990	2,490,559	1.32
High P Compressor	1,561,575	232,721	234,236	69,774	536,730	0.28
High P Tank (7 days)	23,224,921	3,461,198	464,498		3,925,697	2.07
Total	33,698,627	4,601,639	1,322,584	1,028,763	6,952,986	3.67

Scenario 2

Installed electric power requirements	8,500 kW
Annual Production of H2	1,290 tonnes/year

	Size	Size kW (nom)	Annual Energy GWh
Electrolyser	34 cells	6,421	66.5
High P Compressor	1,095 Max cfm	522	4.3
High P Tank (7 days)	2,003 m3 (at 175 bars)		

	Capital Total	Capital per year	O & M per year	Electricity per year	Total per year	\$/kg h2
Electrolyser	6,611,552	673,401	462,809	665,267	1,801,476	1.40
High P Compressor	1,195,211	178,122	179,282	43,175	400,578	0.31
High P Tank (7 days)	15,829,392	2,359,046	316,588		2,675,634	2.07
Total	23,636,155	3,210,569	958,678	708,442	4,877,689	3.78

Table 15: Cost of Compressed Merchant Hydrogen

shipping distances. A single liquid hydrogen tank trailer can transport over 3000 kg of hydrogen whereas a compressed gas tube trailer is limited to around 350 kg.

- The cost of liquid hydrogen is strongly influenced by the capital cost of the liquefier, which typically are high for small scale liquefaction plants (less than 5 tonnes per day).
- Compressor costs are a small portion of the total cost of compressed hydrogen. This option is mostly influenced by on-site storage facility.
- As mentioned in the previous chapter, the benefits from economies of scale in Scenario 1 are partly offset by a low load factor. This explains the small difference in production costs between Scenario 1 and 2 for compressed hydrogen production.
- The liquefier efficiency is usually an important factor of hydrogen liquefaction cost. A low efficiency translates in high electricity cost. However, the relatively low electricity rate applied in this study reduce the influence of liquefier efficiency. For both scenarios, with an efficiency of about 15%, the cost contribution of electricity used for liquefaction accounts for only about 7% of liquefaction costs and about 5% of total production costs (excluding seasonal storage).

4.4.4 Sensitivity Analysis

The sensitivity analysis examines the influence of a number of parameters on the hydrogen total production costs. These parameters include electricity rate, real rate of interest, and liquefier investment cost. Figure 23 shows the results of the sensitivity analysis.

Electricity costs are certainly the dominating factor in an energy intensive industry like electrolytic hydrogen production and will be the key factor in the feasibility of such a venture.

Changes in the liquefier capital cost noticeably impact the cost of the product hydrogen. Conventional liquefier technology is highly capital intensive especially for small-scale liquefaction plant (<5 tonnes per day). A novel refrigeration technology, presently in development, could well enhance the prospect for liquid hydrogen in Fort Smith. Magnetic liquefaction of hydrogen (using a thermomagnetic cycle) is expected to not only improve liquefaction efficiency but also reduce capital cost, especially for plants of capacity lower than 10 tonnes per day [6].

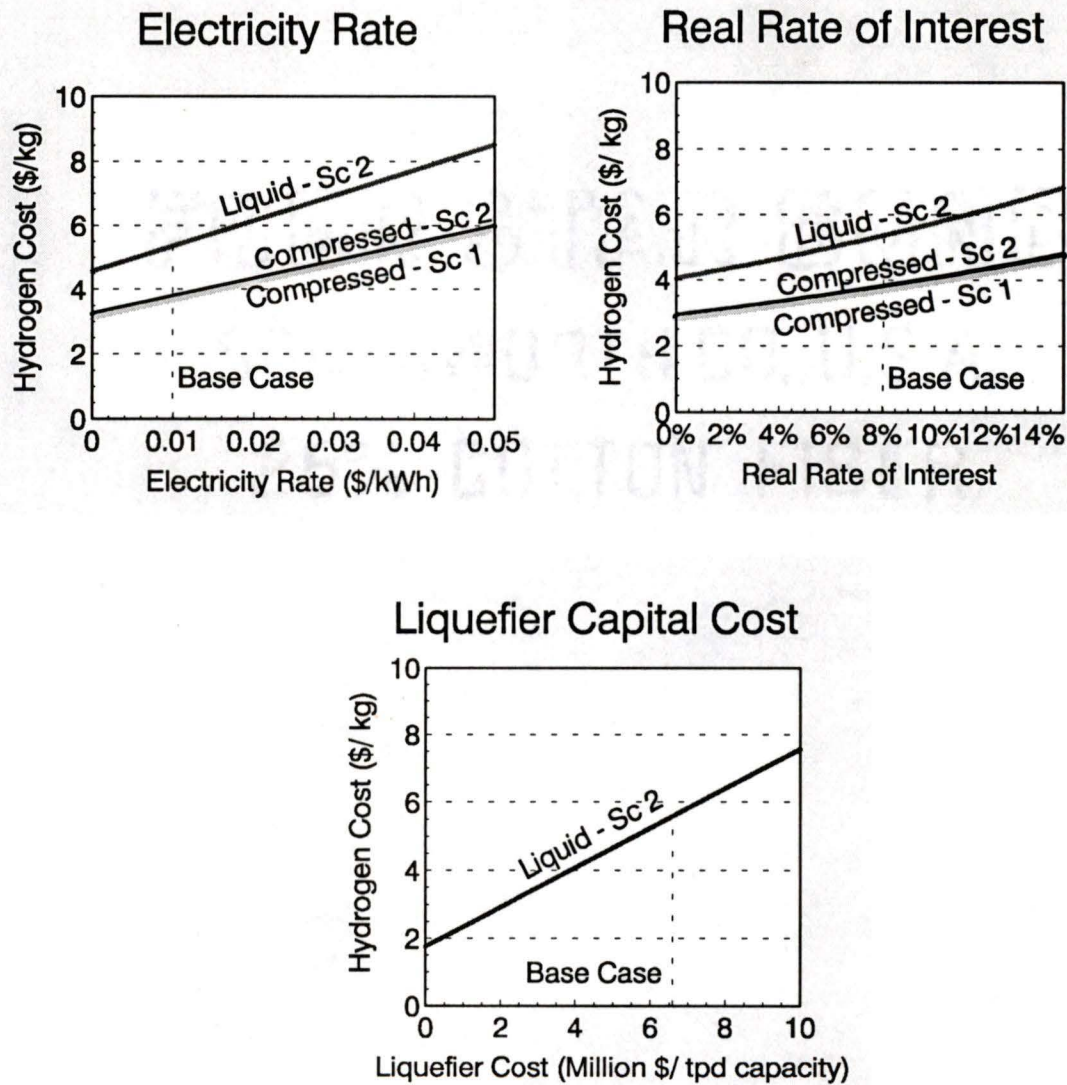


Figure 23: Sensitivity Analysis of Cost Parameters on Merchant Hydrogen Total Production Cost.

4.5 Concluding Comments

The energy required by a state change such as compression or liquefaction reduces the amount of hydrogen that can be produced by the proposed Fort Smith facility. For the case of liquefaction, this reduction is significant.

In the case of liquid hydrogen production, seasonal load following is impractical due to the large requirement for seasonal storage. For the same reason, compressed hydrogen requires a concurrent consumption pattern in order to be practical.

The additional state change also increases the hydrogen production costs. Figure 24 compares the cost of compressed hydrogen and liquefied hydrogen produced in Fort Smith with a range of production costs and market prices in North America. Fort Smith's data excludes transportation costs.

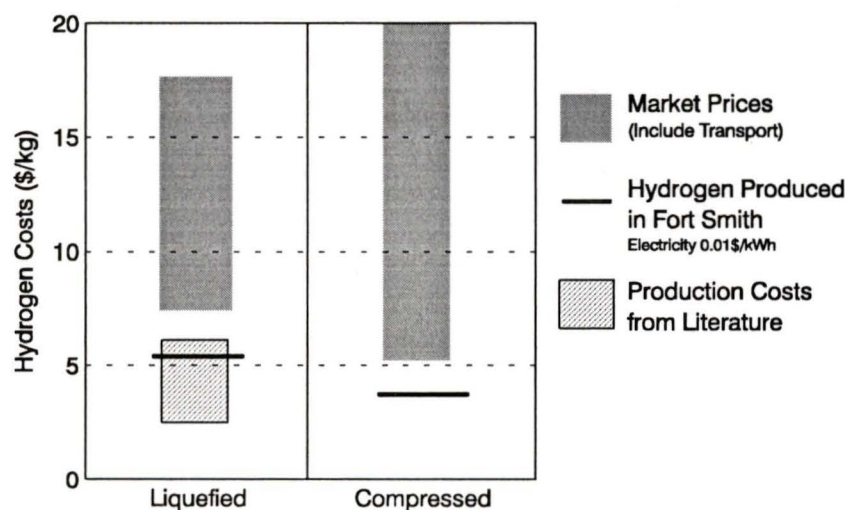


Figure 24: Comparison of Fort Smith Compressed or Liquefied Hydrogen with North American Costs and Market Prices.

- Sources: Air Liquide [100], Linde [120], Moore [37], Scheihing [43], Camford Report [15], Taylor [51], Lin [35].
- Fort Smith data excludes transportation.
- Prices vary with quantity purchased and delivery distance. In the case of compressed hydrogen, purity also influences the market price.
- Production costs vary with production capacity (5 to 40 tonnes per day, using SMR hydrogen with natural gas at \$2.00/GJ and electricity at 5 ¢/kWh).

The results show that merchant hydrogen produced in the Northwest Territories compares favourably in the world hydrogen market. The upper end of market prices presented on Figure 24 represents high purity hydrogen or long distance shipment. These markets are certainly the most promising in the case of Fort Smith merchant hydrogen.

Finally, to fully assess the feasibility of a merchant hydrogen production facility in Fort Smith, a complete market study is required.

Chapter 5

Hydrogen Peroxide

5.1 Market Overview

5.1.1 Commercial Uses of Hydrogen Peroxide

Hydrogen peroxide was discovered in 1818 by the French chemist Louis-Jacques Thenard who first called it oxygenated acid but then realized he had discovered "oxygenated water", H_2O_2 [71]. Hydrogen peroxide is a weakly acidic, clear, colourless liquid that is miscible with water in all proportions. Hydrogen peroxide has been on the market since the middle of the 19th century. Its production and use have increased significantly since 1925 with the development of industrial bleach applications, such as cotton bleaching [65].

Hydrogen peroxide is produced and used in concentration ranging from 3% to 98% weight ratio in a water solution. Concentrations of 50% and 70% are commonly sold since they are preferred for transportation purposes [65]. The buyer may subsequently dilute the solution to meet the required concentration.

Hydrogen peroxide, especially in high concentration, is a strong oxidant^{7,8}. It can be handled safely provided proper precautions are observed in order to avoid undesired or uncontrolled reactions and to avoid physical contact. The usage of hydrogen peroxide has no side effect on the environment since the only products of its decomposition are oxygen and water.

⁷ An oxidant is a substance that brings about oxidation by being reduced and gaining electrons.

⁸ Properties of hydrogen peroxide are presented in Appendix C.

Most of hydrogen peroxide uses are as a non-polluting oxidizing agent. Lower concentrations (3% to 6%) are used in cosmetic applications, such as hair dying, and in medicinal applications as an antiseptic. Hydrogen peroxide is also employed in the manufacture of numerous organic and inorganic chemicals such as polyurethanes and unsaturated polyesters. Derivatives of H_2O_2 are produced for specific applications such as household and detergent bleach. It is also used for metal surface treatment in industry and in mining applications. Direct environmental applications of hydrogen peroxide include treatment of waste water and sewage effluents as well as de-inking of recycled waste paper. High concentration hydrogen peroxide (70% and above) may also be used as an oxidant for the propulsion of underwater and space vehicles. This application was first developed by the German navy and widely used during World War II.

The largest use of hydrogen peroxide today is by far as a bleaching agent. Most cotton fabrics are bleached with alkaline hydrogen peroxide. Lesser quantities are used to bleach wool, silk, and some vegetable and animal fibers. Hydrogen peroxide can also be used to bleach groundwood, chemi-thermomechanical (CTMP) pulp, and chemical (kraft) pulp. With the growing environmental concerns over traditional bleaching agents chlorine and chlorine dioxide, hydrogen peroxide is getting increasing attention from the pulp and paper industry.

5.1.2 Demand and Supply

In 1992, over 1.2 million tonnes⁹ of hydrogen peroxide was produced worldwide. This production represented 68% of the total installed capacity (Table 1). World demand for hydrogen peroxide is expected to grow 7% annually through 1995. The greatest growth is expected in North America and Latin America with 10 to 12% growth rate [60].

In North America, the total demand reached 360 kilotonnes (kt) in 1992 representing a 15% increase over 1991. With 500 kt of capacity in place, the

	Capacity	Production
World Total	1852	1270
Europe	920	610
North America	504	360
Rest of the world	428	300

Table 16: H_2O_2 in the World, 1992.
(kilotonnes/year) [60].

⁹ All capacity, production, consumption, export, import and prices of H_2O_2 are given in terms of mass of the actual H_2O_2 rather than the mass of the entire solution. This is referred to as "100% basis". H_2O_2 is produced and used in a wide range of concentrations in water solution. This convention avoids confusion and one doesn't have to specify what concentration is referred to.

industry is now operating at close to 73%. Utilization bottomed out at the end of 1990 at 66 % [57].

In Canada, the startup of Du Pont Canada's new 36 kt per year hydrogen peroxide plant at Gibbons, Alberta increased Canadian capacity to more than 140 kt/y. Table 17 illustrates the balance of H_2O_2 for Canada, indicating production and consumption as well as imports and exports. As evidenced by the numbers, Canada exhibits an overcapacity of roughly 22 kt/year. Also, Canada has become a net exporter of hydrogen peroxide with the U.S. as the principal export market.

Capacity: 143 kt/year		
Production	120.8	
Imports	13.0	
Consumption		87.4
Exports		46.4
	133.8	133.8

Table 17: 1992 H_2O_2 Canadian Balance.
(in kilotonnes). Source: [72-74]

Canadian consumption of H_2O_2 is dominated by the pulp and paper industry, which accounts for about 65% of the total national consumption. According to Joe Piccione, V.P., Camford Information Services Inc., Toronto, hydrogen peroxide consumption in the Canadian Pulp and Paper Industry grew from 51 kt in 1991 to 57 kt in 1992, despite the overall pulp production decline of 5% [67]. This is due primarily to the increased use of H_2O_2 as a bleaching agent in the pulping process.

Increased demand for hydrogen peroxide will serve to strengthen the North American market. Capacity grew faster than demand in the late 1980s and early 1990s. This overcapacity put downward pressure on hydrogen peroxide prices. The current market price of hydrogen peroxide is about \$1000/tonne [106,114]. Supplies will remain in excess in 1993. However, increasing demand for hydrogen peroxide, coupled with stable capacity, should lead to balanced markets in late 1994. Prices are expected to increase slightly during the second half of 1993 [67].

Quote from a producer [57]:

"Prices will have to go up before any grassroots expansion occurs, and this probably won't happen until 1994/95. Until then, producers will have to utilize incremental expansion capabilities. Operating rates will have to be approaching 90 percent 'to entice people to put money in the market', whether it is through remounts of old facilities or announcements of wholly new ones. Right now, investment levels are not sufficient to justify new capacity."

5.1.3 Hydrogen Peroxide Producers

Table 18 presents the world's major hydrogen peroxide producers, with special attention given to location and plant capacity of North American facilities. Solvay is the world's largest producer of H_2O_2 , occupying about one-third of the European market, and more than one-quarter of the world market.

There are four hydrogen peroxide plants in Canada. The largest Canadian facility is operated by FMC in Prince George, B.C. The FMC plant has a capacity of 41 kt/year and part of this capacity serves the nearby pulp and paper industry. Production of H_2O_2 utilizes hydrogen produced on-site from SMR. Du Pont operates two hydrogen peroxide production plants, one in Gibbons, Alberta and the other in Maitland, Ontario. Both plants have a capacity of 36 kt/year. Gibbons' plant also produces SMR hydrogen. The fourth Canadian facility is located in Bécancour, Québec and is a joint venture between Elf Atochem and L'Air Liquide. The Bécancour plant utilizes by-product hydrogen from a nearby chlor-alkali electrolysis plant.

Company	World Total	North America	
Total	1852	143	Canada
		361	USA
Du Pont	148	36	Gibbons, AB
		36	Maitland, ON
		60	Memphis, TN
FMC	224	41	Prince George, BC
		43	Bayport, TX
		38	Spring Hill, WV
		10	Santa Clara, NM
Chemprox (Elf Atochem/ L'Air Liquide)	150	30	Bécancour, PQ
Solvay	452	50	Deer Park, TX
		50	Longview, WA
Degussa	250	75	Mobile, AL
Eka Nobel	140	35	Columbus, MS
Kemira	65		

Table 18: Major Hydrogen Peroxide Producers and their Capacity in North America and Worldwide.

All numbers in thousands of metric tonnes per year. [60]

Expansion of the North American capacity is being considered by a number of companies [57,60]. Elf Atochem is planning to build its own hydrogen peroxide plant, either in Tacoma, Wash. or Portland, Ore., sometime in 1995 or 1996. Capacity would be around 30 kt/y. Degussa is also planning a 50 kt/y facility in North America for 1997-1998. And Kemira is planning its first North America hydrogen peroxide production plant. Proposed plant capacity is about 34 kt/y. Completion date may be 1995, with the Great Lakes region as a possible location.

5.1.4 Market for Fort Smith

The pulp and paper industries of Northeastern British Columbia and Northern Alberta could constitute a market for hydrogen peroxide produced in Fort Smith. The following section doesn't represent a market study. It is intended to simply give an overview of the pulp and paper industries in the area. A description of hydrogen peroxide use in the bleaching of pulp is also presented.

Table 19 presents a list of all pulp producers in Northeastern B.C. and Northern Alberta as surveyed by the Canadian Pulp & Paper Association. A geographical representation of the pulp mills is presented in Appendix D. Alberta-Pacific Forest Industries Inc. mill at Prosperity (near Athabaska) is not shown on the map since the plant is still under construction.

The pulp type refers to the technique used to produce the pulp. Kraft and Chemithermomechanical pulping systems (CTMP) are the two dominant techniques used for the production of *bleached* pulp. The kraft process is characterized by its consumption of chlorine or substitute chlorine dioxide which create dioxins in effluent discharge. Environmental concerns force the producers of kraft pulp to look for substitutes to replace chlorine and chlorine dioxide. New plants built in Canada increasingly opt for CTMP systems which have the potential to reduce effluent discharge to zero, as in the case of the Millar Western plant in Meadow Lake, Saskatchewan.

Location	Company	Pulp Type ^a
Alberta		
Peace River	Daishowa	Bl kraft
Grande Prairie	Weyerhaeuser ^b	Bl kraft
Slave Lake	Slave Lake Pulp Corp.	CTMP
Whitecourt	Millar Western	CTMP
	Alberta Newsprint Co. Ltd.	TMP, recycled paper
Hinton	Welwood	Bl kraft
Prosperity ^c	Alberta-Pacific Forest Ind.	Bl kraft
British Columbia		
Taylor	Fibreco	CTMP
Chetwynd	Louisiana-Pacific	CTMP
Mackenzie	Fletcher Challenge	Bl kraft
Prince George	Pr. George P&P Mills (2 plants)	Bl, SBl, UBl kraft
	Northwood Pulp	Bl, UBl kraft
Quesnel	Cariboo P&P	Bl kraft
	Quesnel River Pulp	CTMP, TMP

^a Bl=bleached, SBl=semi-bleached, UBl=unbleached, kraft=kraft pulp, CTMP=chemi-thermomechanical pulp, TMP=thermomechanical pulp.

^b Formerly Proctor and Gamble Cellulose Ltd.

^c Expected construction completion in late 1993.

Table 19: Pulp Producers in Northeastern British Columbia and Northern Alberta.
Source: Pulp & Paper Canada, 1993 [69].

H₂O₂ in Pulp and Paper Industry

This section describes the target applications for hydrogen peroxide in the bleaching of pulp [62,66,70,75]. The major advantage of hydrogen peroxide over other bleaching agents, (chlorine and chlorine dioxide), is that it yields only water and oxygen on decomposition, producing no toxic by-products.

Most of the pulp bleached is made by separating wood into its component fibers, either chemically (kraft) or mechanically (CTMP). The principal fiber components are cellulose, hemicellulose, lignin (natural glue holding wood fibers together), and minor amounts of solvent-extractable materials. Virtually all of the color of any pulp resides in its lignin component. It is therefore the principal target of bleaching processes. Lignin has a tendency to get darker when exposed to light.

Mechanical pulp:

In mechanical pulping, wood chips are refined mechanically and much of the original pulpwood lignin is retained. The technique of bleaching involves the discoloration of the lignin and the addition of fillers and/or coatings to mask the effect of light on the retained lignin. Only two brightening agents, hydrogen peroxide and sodium hydrosulfite, are of commercial importance.

According to Le Centre de recherche en pâtes et papiers de l'université du Québec à Trois-Rivières, bleaching of CTMP can be done with 2 stages of 2% H_2O_2 ¹⁰. Bleaching level (a measure of brightness) of 70-80 can be obtained. Kraft pulp can reach 90 bleaching level.

Chemical pulp:

Chemical pulp (mostly kraft, also sulfite) is produced by removing 93%-95% of the lignin in an aqueous solution of chemicals. Subsequent bleaching occurs in several stages. Figure 25 gives an example of a bleaching sequence of kraft pulp in five stages. The diagram shows the combination of chemicals used for different stages.

Hydrogen peroxide is not part of a conventional kraft pulp bleaching sequence. However, intensive research, driven by environmental concerns, gave H_2O_2 several potential applications in the process. Whether or not kraft mills have chosen or will choose to incorporate H_2O_2 in some stages of their bleaching sequence depends on the economic situation as well as political and environmental pressure.

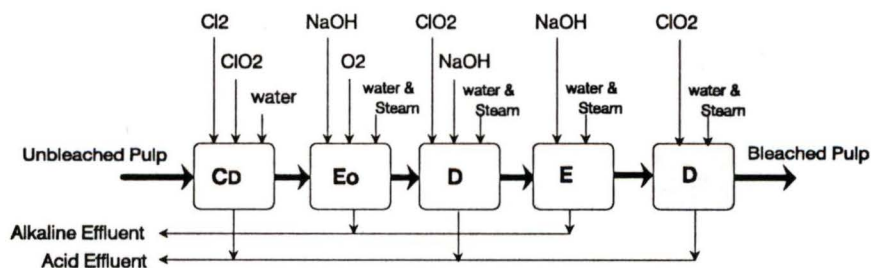


Figure 25: Example of Kraft Pulp Bleaching Sequence.
Letters represent conventional stage notation [70].

¹⁰ X% H_2O_2 means X unit mass of H_2O_2 per 100 unit mass of *dry* pulp.

Here are some examples of potential applications:

- Preceding C_D stage: Based on experimental results, 1.0% H_2O_2 can be used effectively. However, oxygen gives similar results. Since oxygen is about 10 times cheaper than hydrogen peroxide, it is more attractive economically.
- E_o (first extraction) stage: The addition of approximately 0.5% H_2O_2 reduces the chlorine charge by approximately 2% (from ~6% to 4%). This technology is rapidly being retrofitted to commercial bleaching sequences in North America.
- E (second extraction) stage: 0.225% H_2O_2 can replace 0.45% ClO_2 in the preceding D stage and lower the cost of bleaching. The price of ClO_2 is about 80% that of H_2O_2 .
- Some processes use hypochlorite stages resulting in chloroform formation. There are increasing pressures to replace them. Using essentially the same equipment, 0.5% H_2O_2 can effectively replace hypochlorite.
- In the final bleaching stage, hydrogen peroxide can be used in high density storage (about 0.2% H_2O_2) to gain several (up to 8) points in brightness.

Recycled paper:

The increased use of recycled paper has opened up new growth opportunities for hydrogen peroxide. The wood content of mixed papers can cause discoloration problems when chlorine is used for bleaching. Hydrogen peroxide, in combination with some other reagent, can be used successfully as a de-inking aid and a bleaching agent for the secondary fibres.

5.2 Manufacture Overview

Since Thenard's discovery in 1818, a large number of hydrogen peroxide formation reactions have been discovered, and from them, several production techniques have been devised. Figure 26 presents a list of hydrogen peroxide formation reactions.

Several of these reactions yield minuscule amounts of hydrogen peroxide and therefore are not practical for commercial applications. The very first commercial process was derived from Thenard's laboratory experiment, involving the reaction of barium peroxide with an acid.

Commercialization took place some sixty years after the discovery because of the high supply cost of barium.

In 1909, the first commercial *electrochemical process*, involving peroxydisulfuric acid, was established. This process permitted the production of a more pure and more concentrated hydrogen peroxide solution. By 1950, electrochemical processes, accounted for more than 80% of the market.

During that same period of time, other processes received serious interest but failed to be commercialized. These include thermal and electric-discharge reactions of hydrogen and oxygen, cathodic reduction of oxygen, as well as hydrocarbon and nitrogen compound autoxidation.

In 1953, the first large-scale *anthraquinone autoxidation process* was put into operation in the United States by E.I. du Pont de Nemours & Co.

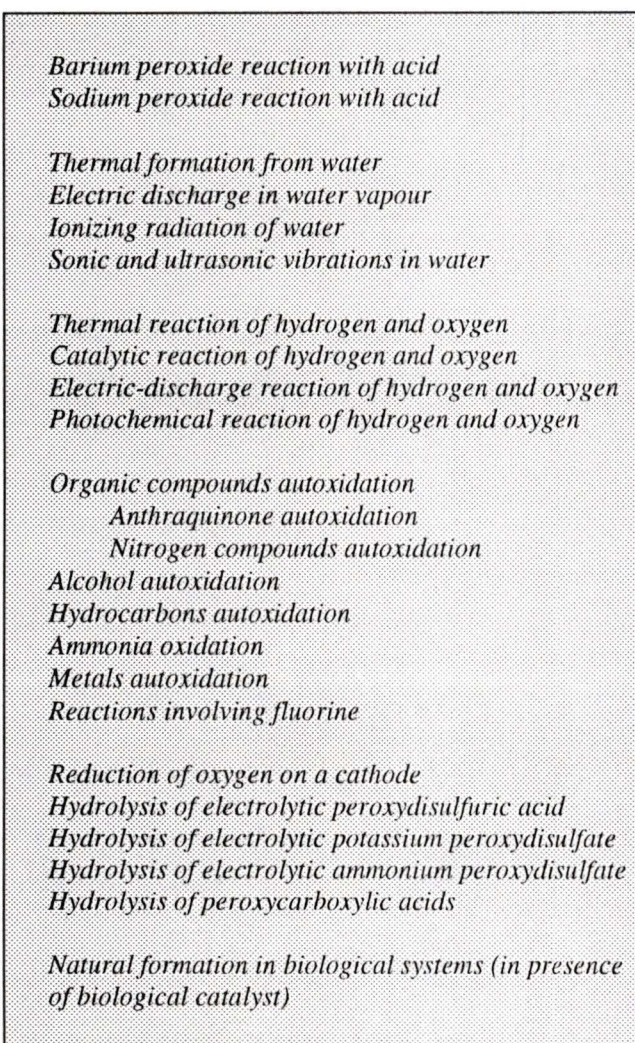


Figure 26: Hydrogen Peroxide Formation Reactions [63,65,71].

With lower investment and operating costs, the anthraquinone process gradually took over the market. All manufacturing facilities built in North America since 1957 use this technology. Electrochemical processes gradually disappeared due to higher capital investment and electric power costs.

During the late 1950s, another process was developed, based on the autoxidation of isopropyl alcohol. A plant using this process was installed in Louisiana by Shell Chemical Company. However, extensive commercialization of this process did not take place. By 1975, more than 90% of the world's hydrogen peroxide production was supplied by the anthraquinone process.

In the 1980s, much attention was given to the direct combination of hydrogen and oxygen using a catalyst for the production of H_2O_2 . Directly combining H_2 and O_2 to obtain H_2O_2 has the potential to be simple and straightforward. The potential simplicity of the process, combined with its relatively inexpensive starting materials suggest that it may exhibit low capital costs suitable for small scale production facilities. Several patents have been granted, but to our knowledge, no commercial plants exist at this time.

At the end of the 1980s, an alkaline electrolytic process involving the reduction of oxygen on a cathode was commercialized by a Canadian company, H-D Tech Inc., a joint venture of Huron Technologies Inc. and Dow Chemical Company. This electrochemical process, which generates hydrogen peroxide in an alkaline solution, was developed specifically to provide hydrogen peroxide for the pulp and paper industry.

This section discusses the following four hydrogen peroxide production processes which have particular relevance in the Fort Smith context:

- Anthraquinone Autoxidation Process: As mentioned before, this process has been globally adopted for the last 35 years and represents the industry standard today. One possible drawback for the Fort Smith case is that this process is usually preferred in large scale production settings.
- Alkaline Electrolytic Process: Manufacturing hydrogen peroxide directly from electricity eliminates the intermediate step of producing hydrogen and oxygen. The principal feedstock of electrochemical processes is electricity, making Fort Smith's excess power an asset.

- Acidic Electrolytic Process: This process dominated the hydrogen peroxide market prior to the anthraquinone process but gradually disappeared because of higher capital costs and electrical power costs. Again, Fort Smith's excess power is an asset.
- Direct Combination of Hydrogen and Oxygen: The potential simplicity of this process could lead to low capital costs suitable for the small size of the proposed Fort Smith plant.

5.2.1 Anthraquinone Autoxidation Process

Anthraquinone autoxidation processes developed worldwide retain the basic features of the Riedl-Pfleiderer process shown in Figure 27. It is a complex process, involving several chemical reactions and treatments. The nature of the chemicals used, other than the anthraquinone base, as well as the specific operating conditions vary between producers. A general description of the process follows [61,63,65,68].

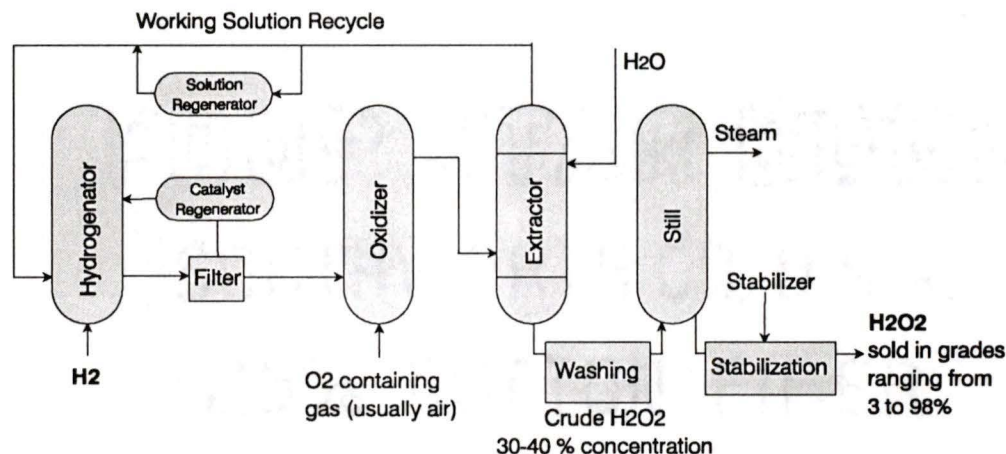


Figure 27: Anthraquinone Oxidation H_2O_2 Production Process.

The *working material* anthraquinone dissolved in a solvent or solvent mixture forms the *working solution*. This working solution undergoes a cycle. In a first step, part of the working material is reduced (captures hydrogen) in the presence of a catalyst and becomes *hydroquinone*. This reaction is carried out at slightly elevated hydrogen partial pressure and below $100^\circ C$. The catalyst is filtered out. Then, the hydrogenated solution is oxidized (reacts with oxygen) with an oxygen-containing gas in an uncatalyzed reaction. The overall rate of this reaction is dependent on the oxygen partial pressure, the temperature and the phase boundary surface area. At this

stage, H_2O_2 is formed and the working material returns to its original form of anthraquinone. Usually the hydrogen peroxide is recovered from the quinone solution by extraction with water. Today's technology yields H_2O_2 concentrations between 30 and 40%. Due to side reactions during the process, the completion of the cycle requires regeneration of the working solution as well as the catalyst used during hydrogenation.

In all current production facilities, the oxidation is carried out using compressed air as the oxygen source. Whether or not the oxygen co-produced by the electrolysis plant could be used is uncertain. Not enough oxygen is produced during electrolysis to convert all the hydrogen produced, however an option would be to enrich the air with oxygen and use this mixture in the oxidation process. The only advantage of partly enriching air with oxygen would be to decrease the air to hydrogen ratio. This could reduce the size of compressors and the compression power requirements.

Discussion with several producers and researchers in the field revealed some scepticism to this idea. Very high concentrations of oxygen represent a safety problem because of the formation of vapour mixtures of explosive composition. A complete analysis of this issue is required at the preliminary design stage.

Following the cycle reactions, the crude hydrogen peroxide aqueous solution has to be purified to remove entrained solvent and quinone during the extraction. Then it is brought to the desired concentration for distribution, usually 50% or 70%. Finally, an adequate stabilizer is added.

Concentration

The concentration of hydrogen peroxide is an issue of importance to all production processes. Different commercial processes yield hydrogen peroxide in different concentrations, usually lower than 40%. At this point, the major part of the solution is still water. For economical reasons, when hydrogen peroxide has to be shipped over relatively long distances, it is usually concentrated further first, typically to 50% or 70%. This can be carried out safely and conveniently by distillation¹¹ at reduced pressure. The rate of decomposition of liquid H_2O_2 ¹²

11 Distillation is a column-type process that separates components of a liquid mixture by taking advantage of their distinct vaporization temperature. Steam is often used as the source of energy.

12 Hydrogen peroxide decomposes according to the reaction: $\text{H}_2\text{O}_2 \rightarrow \text{H}_2\text{O} + \frac{1}{2}\text{O}_2$

increases about 2.3 times every 10°C. A low pressure distillation lowers the temperature of operation and consequently reduces hydrogen peroxide losses.

Concentrating very dilute solutions is uneconomical. For example, to obtain one litre of a 70% solution requires 2.3 litres of a 35% solution from which 1.3 litres of water have to be evaporated. It requires 8.7 litres of a 10% solution from which 7.7 litres of water have to be extracted, and 17.7 litres of a 5% solution from which 16.7 litres of water have to be evaporated. The energy required for concentrating dilute solutions is proportional to the amount of water to be evaporated. This means that a 5% to 70% concentration will require almost 13 times more energy than a 35% to 70% concentration.

Stabilization

The decomposition of hydrogen peroxide is an important characteristic which has to be minimized during manufacture, storage and use, not only for economic reasons, but because release of oxygen and heat may cause safety problems. Decomposition of hydrogen peroxide into water and oxygen generates gas and heat (about 100 kJ/mol).

The mechanism of decomposition depends on many factors including temperature, pH, or the presence of a catalyst. The sole presence of impurities may serve as a catalyst and induce decomposition. The stability of pure hydrogen peroxide solutions increases with increasing concentration. Pure hydrogen peroxide solutions stored in clean passive containers are relatively stable. Commercial solutions, however, invariably contained and are exposed to catalytic impurities and must be stabilized with reagents that deactivate the potential reaction. The quantity and type of stabilizer in commercial solutions are adjusted to meet specific end-use application requirements.

Commercial stabilized hydrogen peroxide properly stored would be expected to lose less than 1% of its hydrogen peroxide content in the course of a year at ambient temperature. Since corrosion is a source of catalytic impurities, aluminum is commonly used for shipping and storing H_2O_2 along with corrosion inhibitors.

5.2.2 Alkaline Electrolytic Process

The alkaline electrolytic process [59] is in many ways similar to the electrolysis of water using unipolar electrolytic cells to produce hydrogen and oxygen. Water containing an alkaline electrolyte (sodium hydroxide, NaOH) is circulated through the anode compartment of the cell

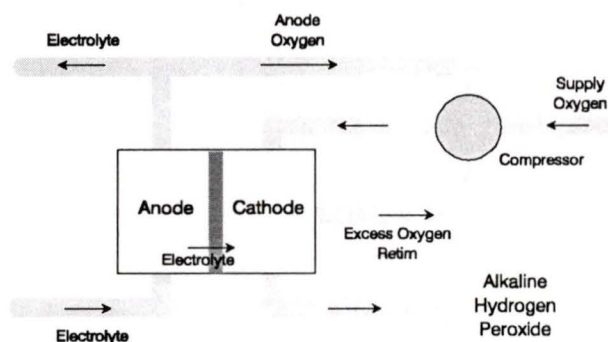


Figure 28: Alkaline Electrolytic Process.

(see Figure 28). When a current is passed through the electrolyte solution, oxygen is evolved on the anode in the same manner as in the electrolysis of water. The particularity of this process resides in the cathode reaction, where hydrogen peroxide rather than hydrogen is produced. Pressurized oxygen gas is fed into the cathode compartment and in the presence of a catalyst, reacts with the electrolyte to form

hydrogen peroxide. A relatively dilute hydrogen peroxide-water solution, also containing sodium hydroxide, exits from the bottom of the cathode compartment.

On first examination, this process appears well suited to the case of Fort Smith by eliminating the intermediate production of hydrogen. Moreover, the principal feedstock of electrochemical processes is electricity, making Fort Smith's excess power an asset. However, discussions with the manufacturer [117] revealed several reasons why this technology is not a practical option for Fort Smith.

The oxygen produced in the anode compartment accounts for less than half of the total amount of oxygen required in the cathode reaction. Consequently, an external supply of oxygen is necessary. This would require the installation of an oxygen plant in the Fort Smith area, and therefore a substantial increase in the capital investment.

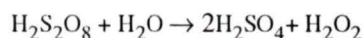
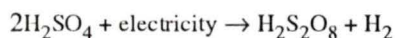
Furthermore, each cell represents a power of about 11 kW. An available power of 8.5 MW from the Taltson Dam could supply over 750 cells, about 10 times larger than the conventional system design at the present time.

Finally and most importantly, the product hydrogen peroxide is very dilute and therefore unstable. For this reason, the system is designed to be integrated with the bleach plant operation. The product hydrogen peroxide must be used on site as produced to be economical. Consequently, this process is inappropriate for the Fort Smith case.

5.2.3 Acidic Electrolytic Process

Prior to the anthraquinone process, hydrogen peroxide was mostly produced through electrolytic processes involving the hydrolysis of peroxy compounds obtained by electrolysis. However, this process slowly disappeared after 1960 and very little recent information regarding the process exists. One of the rare volumes entirely dedicated to hydrogen peroxide, written by Schumb, Satterfield and Wentworth in 1955 [71] and still widely used as a reference today, gives an excellent overview of electrolytic processes, which were still dominating the market at the time of the publication. The following information is extracted from this book and updated when necessary.

Three different processes had some commercial significance: peroxydisulfuric acid ($\text{H}_2\text{S}_2\text{O}_8$), potassium peroxydisulfate ($\text{K}_2\text{S}_2\text{O}_8$) and ammonium peroxydisulfate ($(\text{NH}_4)_2\text{S}_2\text{O}_8$). The manufacture of hydrogen peroxide is carried out in two principal stages, electrolysis and hydrolysis. For example, in the peroxydisulfuric acid process, a sulfuric acid solution is electrolyzed and the resulting solution, now containing peroxydisulfuric acid, is hydrolysed to form hydrogen peroxide.



Similar procedures apply to different chemical compounds in the other two processes, with $\text{K}_2\text{S}_2\text{O}_8$ having an intermediate reaction of precipitation. All processes yield about 35% hydrogen peroxide concentration.

Electrolytic cell design varies for each process but all use platinum as the anode material. Cells are arranged in series with respect to both solution and electricity. The hydrogen evolved during the electrolysis is vented out. For each of these processes, an extensive and continuing purification of chemicals and electrolyte is critical.

Electricity is required for electrolysis and steam is required for hydrolysis and distillation. Energy requirements vary between processes and according to Schumb et al. the range is as follow:

Electricity	15 to 20 kWh per kg of H_2O_2
Steam	25 to 50 tonnes per tonnes of H_2O_2

In a Fort Smith scenario, a supplemental amount of steam would be required to further concentrate the hydrogen peroxide from 35% to 70%, corresponding to the probable desired concentration for shipment. This amount of steam is estimated at 1.5 tonnes per tonne of H_2O_2 which is insignificant when compared to the previous figures.

Capital investment and maintenance costs are two other significant components of the hydrogen peroxide production costs. Schumb et al. give part of the investment corresponding to the mass of platinum required in the system. This amount varies between 28 and 68 g per annual tonne capacity. At the given rate of platinum loss by the reaction, the initial amount would be totally consumed after about 10 years. Finally, they also evaluate the maintenance costs as representing 35%-40% of the total manufacturing costs.

Could the electrolytic process regain competitiveness in a context such as Fort Smith excess available power? Using Schumb's process parameters, a base case electricity rate of \$0.01/kWh and a platinum market price of \$17/g, preliminary calculations give a total hydrogen peroxide production cost well exceeding the current market price of \$1000/tonne.

These preliminary calculations show that the acidic electrolytic process proves not to be competitive with the anthraquinone process despite the availability of excess generating capacity at the Taltson Dam. Not only power requirements, but high capital investment and excessive maintenance costs certainly contributed to the gradual disappearance of this process some thirty years ago.

5.2.4 Direct Combination of Hydrogen and Oxygen

The possibility of producing hydrogen peroxide industrially by direct reaction of the elements has intrigued investigators for almost 100 years. A major constraint however renders their work hazardous. Hydrogen and oxygen gas mixture is highly explosive under a wide range of

circumstances determined by the mixture composition, the temperature, the pressure and, an external ignition source such as a spark or a hot wire. Under specific conditions, the safe production of hydrogen peroxide has been demonstrated by thermal or electric-discharge induced formation [71]. However, the low production yield and the high power costs have kept these processes from reaching commercial application.

More recent activities have focused on processes using catalysts. Hydrogen and oxygen react in an acidic aqueous medium in the presence of a platinum-group metal catalyst and additives to produce hydrogen peroxide.

Du Pont

In 1988, Du Pont announced a new process in which H_2 and O_2 react in the presence of a platinum metal catalyst and halide ion within an acidic aqueous environment [54,55]. The patented process will require much lower capital investment due to the reduced number of operations required. Savings up to 50% have been quoted. Preferred operating conditions are 0-25 °C, and 500-2500 psi. The single-step reaction can enable producers to build plants of capacities ranging from 7 to 23 kt/y, compared with the 30-36 kt/y sizes that are presently required to achieve economies of scale for the multistep anthraquinone process.

Two contacts at Du Pont, Canada and United States, however, stated that this project is not an active program anymore. Studies for commercialization of the process revealed that overcoming the risk associated with combining H_2 and O_2 resulted in capital costs substantially higher than those envisioned.

Albchem and University of Alberta

In Alberta, another research venture is presently under way involving the collaboration of Albchem Industries Ltd. and University of Alberta [56,132]. Albchem Industries Ltd., a producer of sodium chlorate, hopes to convert by-product hydrogen into hydrogen peroxide. Financing for the project is being provided by Albchem, the Linde Division of Praxair Canada, and the Research and Technology Branch of Alberta Energy.

Currently, between 5 and 8 tonnes of hydrogen are produced daily by Albchem during electrolysis of sodium chloride to make sodium chlorate. Ironically, the main product, sodium

chlorate, is sold to pulp and paper mills for subsequent production of chlorine dioxide, a competitor of hydrogen peroxide in some stages of pulp bleaching.

Potentially, 25 kt/y of hydrogen peroxide could be produced from Albchem's surplus hydrogen. The production method investigated involves the combination of hydrogen and oxygen in the presence of a catalyst. This method was invented by Dr. K.T. Chuang, a professor in the Chemical Engineering Department of the University of Alberta. A 100 times scale-up of laboratory scale is being studied. Due to the confidentiality of this research, no further information was made available [132].

This process is also being seriously investigated by some Japanese companies. Asahi Gas Chemical as well as Tokuyama Soda Co., Ltd. both have several patents regarding the process. However, no information was found regarding commercial application of the process today.

5.3 Analysis

A review of commercial processes has revealed that the anthraquinone process is the most suitable for the Fort Smith context. The anthraquinone process represents the industry standard today. Meanwhile, the other processes discussed were found to be inappropriate for a variety of reasons.

- The alkaline electrolytic process, developed specifically for the pulp and paper industry, produces a dilute, unstable solution and is therefore economical only when integrated with the bleach plant operation.
- The acidic electrolytic process, which dominated the market 30 years ago, is expensive in comparison with the anthraquinone process in terms of capital, energy and maintenance costs. This is the case despite the availability of surplus electricity at the Taltson Dam.
- The direct combination of H_2 and O_2 promises low capital costs for small plant sizes. Nevertheless, to our knowledge, no commercial systems have materialized.

This section examines the techno-economic characteristics of a hydrogen peroxide production facility in the Fort Smith area, based on the anthraquinone process. The analysis determines the quantity of hydrogen peroxide that can be produced for three different scenarios, as well as the life cycle cost associated with its production. The production costs are compared with estimated

production costs for current producers. Sensitivity analysis looks at the influence of key plant factors on the hydrogen peroxide production cost.

5.3.1 Scenario Development

The anthraquinone process requires a constant supply of hydrogen to optimize operation performance. For this reason, hydrogen production under seasonal load following conditions is not a viable solution.

The amount of hydrogen peroxide produced in Fort Smith depends on the quantity of electricity used by the anthraquinone process. Each unit of electricity used in the formation of H_2O_2 will decrease the amount of hydrogen produced and with it the annual capacity of hydrogen peroxide. Energy requirements in the anthraquinone process include electricity for compressors, pumps, and ancillaries as well as process steam, partly to concentrate the crude solution to shipment concentration.

Process steam is usually produced from natural gas, oil or recovery heat. In Fort Smith, the most appropriate sources of heat for steam generation are electricity and heating oil. Wood pellets would also constitute an option given an assured supply was made available [92]. Whether or not electricity is used for raising steam will have a direct impact on the annual capacity of the plant as well as on the economics of production. Therefore, the analysis considers three scenarios to satisfy the energy requirements of the hydrogen peroxide production plant.

Scenario 1: The annual constant excess power of 8.5 MW is used for hydrogen production, hydrogen peroxide production and steam production.

Scenario 2: The annual constant excess power of 8.5 MW is used for hydrogen production and hydrogen peroxide production only. All steam is produced by a conventional boiler, which utilizes imported heating oil or wood pellets.

Scenario 3: The annual constant excess power of 8.5 MW is used for hydrogen production and hydrogen peroxide production only. Steam is partly produced from seasonal off-peak excess power and partly from imported heating oil or wood pellets when peak excess power is insufficient.

5.3.2 Production Plant Capacity

The anthraquinone process, according to two different producers, uses 700 Nm³ of hydrogen per tonne of hydrogen peroxide produced. In other words, each unit mass of hydrogen produces 16.15 unit masses of H₂O₂. Comparing with the ideal conversion ratio¹³ gives an H₂ conversion efficiency of 96%.

Typical electricity consumption, as obtained from manufacturers, indicates an average of 800 kWh/tonne of H₂O₂. This includes both process and ancillary requirements. Steam consumption, estimated from producers' quotes, is about 2 tonnes per tonne of H₂O₂¹⁴. The energy requirements for raising process steam depends on the boiler efficiency.

Steam from electricity: Assuming an efficiency of 96% and feed water at an average temperature of 20°C, the electric boiler requires 2.85 GJ of energy to produce 1 tonne of steam. Therefore, 5.7 GJ (1580 kWh) per tonne of H₂O₂ is required for steam generation.

Steam from fuel: Assuming a conventional boiler efficiency of 85%, 6.4 GJ (1780 kWh) per tonne of H₂O₂ is required for the production of process steam.¹⁵

Table 20 quantifies the annual production of H₂ and H₂O₂ for the three scenarios.

	H ₂ Production (tonnes/year) ^a	H ₂ O ₂ Production (kilotonnes/year) ^b
Scenario 1: Steam from electricity	758	12.2
Scenario 2: Steam from fuel	1100	17.8
Scenario 3: Steam from electricity and fuel	1100	17.8

^a Using same technology and load curve as in Part II.

^b Includes a 96% hydrogen conversion efficiency.

Table 20: Annual Production of Hydrogen Peroxide.

¹³ The ideal conversion is the stoichiometric conversion $\text{H}_2 + \text{O}_2 \rightarrow \text{H}_2\text{O}_2$ having a mass ratio of H₂ to H₂O₂ equal to 1 to 16.86.

¹⁴ The typical state of process steam is saturated vapour at 6 or 7 bars.

¹⁵ One option to lower the energy requirement for steam is to use the cooling water coming out of the electrolyser to be evaporated as steam. 330 tonnes of cooling water are used for each tonne of hydrogen, translating into about 20 tonnes of water per tonne of H₂O₂. However, only two tonnes of steam are required per tonne of H₂O₂. Therefore, only 10% of the electrolyser heat loss can be captured. This translates into an energy savings for steam production of less than 4%.

When only the electrical requirements of H_2 and H_2O_2 production are fulfilled by the constant power available all year (8.5 MW), the maximum annual production of H_2O_2 is 17.8 kt/year, as shown in Scenario 2 and 3. If process steam is entirely produced in electric boilers, as in Scenario 1, the annual yield of H_2O_2 is only 12.2 kt/y.

The preference of one scenario over an other depends on the economies of scale and the relative costs of steam produced from electricity vs steam produced from a fuel.

5.3.3 Economic Analysis

Because of the complexity of the anthraquinone autoxidation process, most hydrogen peroxide plants are owned and built by less than a dozen large, experienced producing companies. Designing a plant using the anthraquinone technology from scratch would be a serious challenge for any engineering company. For the very same reason that large producers own and build their own plants, any information required for even a primary pre-feasibility study is totally nonexistent in the literature and very difficult to obtain from producers. Estimated capital investments are of public knowledge but most data related to operation costs is secret¹⁶. The following section examines the components of the production costs and puts them into perspective with the Fort Smith context.

Hydrogen peroxide market price in North America fluctuates around \$1000/tonne. A first approximation of an average production cost could fall between \$550 and \$650 per tonne. According to producers, capital investment accounts for slightly more than one-third of the production costs. Labour, maintenance and overhead as well as raw materials and energy costs form the remaining two-thirds.

Investment

35 kt plant capacity is quoted by all companies as being the minimum size to achieve economies of scale in North America today. Capital investment for this size of plant varies between 80 and 125 million dollars, or equivalently \$2300 to \$3600 per annual tonne of H_2O_2 capacity [64]. The

¹⁶ As agreed with hydrogen peroxide manufacturers, for confidentiality purposes, no corporate name is cited with the information provided. All Canadian manufacturers were contacted, as well as some American and European ones [106,108-111,114,129,130].

upper limit corresponds to a fully stand alone plant. This includes a hydrogen production plant (using steam methane reforming process), a steam generation plant (boilers) and cooling tower, and the hydrogen peroxide plant itself. The lower limit includes the H_2O_2 plant only, usually located in an industrial area where there is access to hydrogen and steam from neighbouring industries.

Smaller plants do exist but only in specific markets such as South America and Asia. For example, Kemira has just completed a 20 kt/y plant in Japan in a 50/50 joint venture with a Japanese company [60]. The investment is believed to be 62.5 million dollars (3125 \$/tonne per year). Degussa is building a 5 kt/y in Argentina for an estimated cost of 25 million dollars (5000\$/t/y) [64]. Solvay and OxySynthese both partly own 20 kt/y plants in Brazil and Japan respectively, Eka Nobel owns a 10 kt/y plant in Venezuela and FMC a 10 kt/y plant at Santa Clara, Mexico [60]. A Chinese company has recently developed its own version of the anthraquinone process and entered the international market with a 5 kt plant in Indonesia [58].

In Fort Smith, hydrogen is produced via electrolysis and this part of the investment will be considered separately. However, no process steam is available in the area, imposing the need for a steam generation plant. According to the previous data, investment in Fort Smith is assumed to be 3300 and 3900 \$/t/y for plant capacities of 17.8 and 12.2 kt/y, respectively.

A lifetime of 30 years and a real rate of interest of 8% are used for the Fort Smith analysis. The oldest large scale plant in the world has been in operation for 40 years in Memphis, Tennessee, but has undergone renovation since then.

Raw Materials

Hydrogen, air, water, and purifying and stabilizing agents are the raw materials consumed by the reaction to produce hydrogen peroxide. Also, some of the chemicals, which undergo a cycle during the process, cannot be totally recycled and need to be replenished.

Hydrogen

In general, hydrogen may come from different sources, such as a nearby chemical plant (for example, by-product hydrogen from a chlor-alkali plant), steam methane reforming, or electrolysis as in the case of the Brazil Solvay plant and the proposed Fort Smith plant.

Fort Smith could benefit from low cost hydrogen given favourable electricity rates. An electrolytic hydrogen production plant requires very low supervision and maintenance. In cases where the production is concurrent with the activities of another process, supervision and maintenance can easily be carried out by personnel in place for the other process. Therefore, electricity and capital remain the two only significant components of the costs. Again, a rate of \$0.01/kWh for electricity is assumed for the base case. Under these conditions, hydrogen production costs vary between \$1.00 and \$1.05 per kg, depending on the plant capacity.

Chemicals

During the anthraquinone cycle, degradation products are formed and losses of the working solution are inevitable. Also, the catalyst essential for the hydrogenation reaction is never fully restored to its optimum activity by the regeneration process. Supported Raney nickel or supported palladium was reported in the late 1970s literature as being commonly used along with a set of reagents. Other chemicals are also required for different purposes such as regeneration, purification and stabilization. A survey of all the chemicals as well as their rate of use is beyond the scope of this study. One can suspect though that they constitute a significant portion of the costs, especially the catalyst and the anthraquinone which are carefully regenerated. As an example, anthraquinone has to be replaced in the working solution at a rate of 1 to 3 kg for each tonne of H_2O_2 produced. Anthraquinone price is about \$20 per kg. Finally, as reported by producers, chemicals don't represent a large volume, therefore, delivery to Fort Smith should not add significantly to their costs of purchase.

Energy

It was shown before that although not a large amount of electricity is required in the process, a substantial amount of steam needs to be provided. The energy costs associated with steam production are given in Table 21.

The industrial price of heating oil in Fort Smith is \$0.29 /litre (7.07\$/GJ)¹⁷. In the recent study prepared for The Northwest Territories Development Corporation and The Science Institute of the Northwest Territories by Stanley Associates Engineering Ltd. [92], a wood pellet plant was shown to be cost-effective at a pellet retail price of \$200/tonne (10.50\$/GJ). The lower heating

¹⁷ Personal communications with Esso Petroleum Canada in Fort Smith and Edmonton.

Steam (options)	GJ required per tonne H ₂ O ₂	\$/GJ	\$/tonne H ₂ O ₂
from electricity	5.7	2.78 ^a	15.00
from heating oil	6.4	7.07	45.30
from wood pellets	6.4	10.50	67.20

^a \$0.01/kWh

Table 21: H₂O₂ Production Energy Costs for Steam Requirements.

values of heating oil and wood pellets are 41.2 GJ/litre and 19.1 GJ/tonne respectively. Producing steam using wood pellets implies a consumption of wood pellets of about 6400 tonnes annually.

Fixed Operating Costs

Based on a traditional hierarchy, about 50 people are required to operate a 30 to 40 kt per year H₂O₂ production plant on three shifts. About 20 people form the operation crew. The rest comprises supervision, laboratory, maintenance and general overhead, including plant manager, director of operation, personnel, marketing, accounting, and engineering. It is unlikely that the work load of the employees is a strong function of the volume of production. As reported by producers, a small plant requires close to the same number of people as a larger plant.

The fixed operating costs are estimated according to a scheme typical for chemical plant analysis. For the proposed Fort Smith plant, this translates as follows:

- 16 people form the operation crew with an average salary of \$30,000/year.
- 8 people are required for supervision and laboratory with an average salary of 35,000\$/year.
- Benefits add 35% to the previous salaries.
- General plant overhead (administration) adds 65% of the previous salaries. Part of the overhead expenses can be contractual.
- Maintenance, including material and labour, is taken as a percentage of the hydrogen peroxide plant investment level. 3% is considered in this study.
- 1.5% of total investment is applied for insurance, property taxes and other expenses.

Results

First, as a basis for comparison and also to evaluate the importance of chemical costs on the total production costs of hydrogen peroxide, estimated production costs of existing producers are constructed. Two types of production plants are compared. One is a fully stand alone plant, including on-site hydrogen and steam production. The other one is located in an industrial area where hydrogen is available as a by-product of a nearby chemical plant and industrial process steam can be purchased. Both plants have an annual production capacity of 36 kt of H_2O_2 . Tables 22 and 23 present the estimated production costs for each of these plants.

For the stand alone plant, hydrogen is produced from steam methane reforming. Hydrogen cost is evaluated using Figure 14. A 36 kt H_2O_2 plant requires about 2000 annual tonnes capacity of H_2 or about 6 tonnes per day. According to Figure 14, the production cost of H_2 using steam methane reforming is about \$2.00/kg at that level of capacity. However, in an integrated industrial setting, part of the operating costs for hydrogen production are shared with the H_2O_2 plant. Therefore, hydrogen cost is estimated at \$1.70/kg.

By-product hydrogen, used by the second plant, is the cheapest way to obtain hydrogen where available but it is not a free commodity as one could suppose. The producer was most likely using this hydrogen for heat generation (steam production or other). This heating value has to be replaced with some other fuel. Also, if no other source for hydrogen is available in the area, by-product hydrogen may represent an interesting profit opportunity for the supplier. The primary competitor would be an SMR plant. Impurities also have to be dealt with. With all these considerations, by-product hydrogen costs could easily vary between \$0.70 and \$1.50 per kg. \$1.25 is used here.

In the stand alone plant, steam is produced using natural gas at 2 \$/GJ, giving a steam cost of 14 \$/tonne of H_2O_2 . Process steam available in an industrial area may be sold for 10-15 \$/tonne of steam corresponding to 20-30 \$/tonne of H_2O_2 .

Looking at the production costs obtained from these figures and using the assumption that total production costs fall between \$550 and \$650 per tonne, chemicals account for some \$60 to \$100 per tonne of H_2O_2 . For both cases, investment represents about one-third of the total production costs of hydrogen peroxide.

Existing Producers - Stand Alone Plant

Estimated Hydrogen Peroxide Production Costs

Annual Production of H ₂ O ₂	36000 tonnes/year			
Electricity Rate	0.05 \$/kWh			
Real Rate of Interest	8%			
Plant Lifetime	30 years			
	Amount	Unit cost	Annual cost	Per tonne of H ₂ O ₂
Investment	\$90,000,000	2,500 \$/tpy	7,994,469	222
Capital for SMR sunk in hydrogen cost				
Variable Operating Costs:				
Hydrogen supply by SMR (includes capital, labour, O&M, NG)	63 kg/tonne	1.70 \$/kg	3,855,600	107
Electricity	800 kWh/tonne		1,440,000	40
Energy for steam (natural gas)	6.44 GJ/tonne	2.00 \$/GJ	463,362	13
Other raw materials (chemicals)	0		0	0
Total variable without chemicals				160
Fixed Operating Costs:		Average		
Maintenance, material & labour	3.0% of inv.		2,700,000	75
Labour	20 people	30000 \$/person	600,000	17
Supervision+Lab Tech	10 people	35000 \$/person	350,000	10
Direct labour overhead	30% Labour+Sup		285,000	8
General plant overhead	65% Labour+Sup		617,500	17
Other (insurance, etc.)	1.5% of inv.		1,350,000	38
Total fixed				164
Total Investment	\$90,000,000			
Total Production Costs, without chemicals			\$19,655,931	\$546
Estimated Chemical Costs				60 - 100
Total Production Costs				\$606-\$646

Table 22: Estimated Hydrogen Peroxide Production Costs for a Stand-Alone Plant.

Hydrogen is produced from steam methane reforming and steam is produced using natural gas. The annual capacity of the plant is 36 kt of H₂O₂.

Existing Producers - Industrial Area
Estimated Hydrogen Peroxide Production Costs

Annual Production of H ₂ O ₂	36000 tonnes/year
Electricity Rate	0.05 \$/kWh
Real Rate of Interest	8%
Plant Lifetime	30 years

	Amount	Unit cost	Annual cost	Per tonne of H ₂ O ₂
Investment	\$80,000,000	2,222 \$/tpy	7,106,195	197
Variable Operating Costs:				
Hydrogen supply	63 kg/tonne	1.25 \$/kg	2,835,000	79
Electricity	800 kWh/tonne		1,440,000	40
Steam	2.00 tonne/tonne	12.00 \$/tonne	864,000	24
Other raw materials (chemicals)	0		0	0
Total variable without chemicals				143
Fixed Operating Costs:		Average		
Maintenance, material & labour	3.0% of inv.		2,400,000	67
Labour	20 people	30000 \$/person	600,000	17
Supervision+Lab Tech	10 people	35000 \$/person	350,000	10
Direct Labour overhead	30% Labour+Sup		285,000	8
General plant overhead	65% Labour+Sup		617,500	17
Other (insurance, etc.)	1.5% of inv.		1,200,000	33
Total fixed				151
Total Investment	\$80,000,000			
Total Production Costs, without chemicals			\$17,697,695	\$492
Estimated Chemical Costs				60 - 100
Total Production Costs				\$552-\$592

Table 23: Estimated Hydrogen Peroxide Production Costs for a Plant Located in an Industrial Area.

By-product hydrogen and process steam are purchased from nearby facilities. The annual capacity of the plant is 36 kt of H₂O₂.

The three scenarios representing Fort Smith production of hydrogen peroxide, are summarized in Table 24, Table 25 and Table 26. The costs of chemicals are those estimated from production costs of existing producers. Production costs for Scenario 1 range from \$800 to \$840 per tonne of hydrogen peroxide. Production costs for Scenario 2 are lower ranging from \$700 to \$760 per tonne. In Scenario 3, production costs are the lowest of the three scenarios ranging from \$670 to \$715 per tonne of hydrogen peroxide.

Scenario 2 and 3 clearly benefit from economies of scale over Scenario 1. At a base case rate of \$0.01/kWh for electricity, steam production in an electric boiler is more advantageous than using a more expensive fuel as a source for heat. However, the resulting decrease in annual production capacity, when all the steam is produced from electricity as in Scenario 1, more than offsets the potential benefit of lower steam cost. This is particularly evident from the investment and fixed operating costs components.

Given a market price for hydrogen peroxide of \$1000/tonne, all scenarios are at the upper limit of economic viability. However, Scenario 3 has more potential to attract investment by offering a larger margin for profit and return on investment.

Comparing these Scenarios, and in particular Scenario 3, to the estimated production costs of existing producers, a few points can be made.

- A hydrogen peroxide plant in Fort Smith can benefit from lower hydrogen supply costs as well as electricity costs compared to conventional plants. Combined savings of 40 to 50% can be obtained for electricity and hydrogen supply.
- The small scale of the production facility is a barrier to competitive hydrogen peroxide production costs in Fort Smith. Small scale plants are characterized by high marginal capital investment and high labour requirements per unit of output. Investment and fixed operations costs in Fort Smith's best case scenario (Scenario 3) are, together, 35% to 50% higher than those of worldscale (36 kt/y) production facilities.
- In conventional production facilities, hydrogen and electricity costs represent less than 25% of the total production costs whereas investment and fixed operation costs account for more than 60%. Consequently, a change of the latter has a greater influence on total hydrogen peroxide production costs than a change in hydrogen and electricity supply costs.

Fort Smith - Scenario 1
Hydrogen Peroxide Production Costs

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Plant Lifetime	30 years
Annual Production of H2O2	12242 tonnes/year
Annual Production of H2	758 tonnes/year
Installed electric power requirements	8.41 MW

Hydrogen	Amount	Unit cost	Annual cost	Per tonne of H2
Electrolyser	20 cells			
	or 3,776 kW (nominal)			
	or 4,725 kW (max)			
Investment	\$3,983,982	1,055 \$/kW (nom)	405,777	535
Average Electricity	51.6 kWh/kg		391,052	516
Operation	Labour and maintenance included with H2O2			
Total			\$796,830	\$1,051
Hydrogen Peroxide	Amount	Unit cost	Annual cost	Per tonne of H2O2
Investment	\$47,742,630	3,900 \$/tpy	4,240,855	346
Variable Operating Costs:				
Hydrogen supply	63 kg/tonne	1.05 \$/kg	810,734	66
Other raw materials (chemicals)				60 - 100
Electricity	800 kWh/tonne		97,934	8
Electricity for steam	1,583 kWh/tonne		193,765	16
Total Variable			Low	150
			High	190
Fixed Operating Costs:				
		Average		
Maintenance, material & labour	3.0% of H2O2 inv.		1,432,279	117
Labour	16 people	30000 \$/person	480,000	39
Supervision+Lab Tech	8 people	35000 \$/person	280,000	23
Direct Labour overhead	30% Labour+Sup		228,000	19
General plant overhead	65% Labour+Sup		494,000	40
Other (insurance, etc.)	1.5% of total inv.		775,899	63
Total fixed			3,690,178	301
Total Investment	\$51,726,612			
Total Production Costs			Low \$13,458,146	\$798
			High \$13,947,814	\$838

Table 24: Hydrogen Peroxide Production Costs for Scenario 1.
All process steam is produced from electricity.

Fort Smith - Scenario 2
Hydrogen Peroxide Production Costs

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Plant lifetime	30 years
Annual production of H2O2	17754 tonnes/year
Annual production of H2	1,099 tonnes/year
Installed electric power requirements	8.57 MW

Hydrogen	Amount	Unit cost	Annual cost	Per tonne of H2
Electrolyser	29 cells			
	or 5,474 kW (nominal)			
	or 6,852 kW (max)			
Investment	\$5,357,598	979 \$/kW (nom)	545,683	496
Average Electricity	51.6 kWh/kg		567,132	516
Operation	Labour and maintenance included with H2O2			
Total			\$1,112,815	\$1,012

Hydrogen Peroxide	Amount	Unit cost	Annual cost	Per tonne of H2O2
Investment	\$56,812,533	3,200 \$/tpy	5,046,511	284
Variable Operating Costs:				
Hydrogen supply	63 kg/tonne	1.01 \$/kg	1,132,234	64
Other raw materials (chemicals)				60 - 100
Electricity	800 kWh/tonne		142,031	8
Energy for steam	Heating oil 6.44 GJ/tonne	7.07 \$/GJ	808,157	46
	or Wood pellets 6.44 GJ/tonne	10.50 \$/GJ	1,199,695	68
Total Variable			Low	177
			High	239
Fixed Operating Costs:		Average		
Maintenance, material & labour	3.0% of H2O2 inv.		1,704,376	96
Labour	16 people	30000 \$/person	480,000	27
Supervision+Lab tech	8 people	35000 \$/person	280,000	16
Direct labour overhead	30% Labour+Sup		228,000	13
General plant overhead	65% Labour+Sup		494,000	28
Other (insurance, etc.)	1.5% of total inv.		932,552	53
Total fixed				232
Total Investment	\$62,170,131			
Total Production Costs			Low \$12,313,096	\$694
			High \$13,414,791	\$756

Table 25: Hydrogen Peroxide Production Costs for Scenario 2.
All process steam is produced from a fuel.

Fort Smith - Scenario 3

Hydrogen Peroxide Production Costs

Electricity rate	0.01 \$/kWh
Real rate of interest	8%
Onstream time	94.5%
Plant lifetime	30 years

Annual production of H2O2	17754 tonnes/year
Annual production of H2	1,099 tonnes/year
Installed electric power requirements	11.97 MW

Hydrogen	Amount	Unit cost	Annual cost	Per tonne of H2
Electrolyser	29 cells or 5,474 kW (nominal) or 6,852 kW (max)			
Investment	\$5,357,598	979 \$/kW (nom)	545,683	496
Average Electricity	51.6 kWh/kg		567,132	516
Operation	Labour and maintenance included with H2O2			
Total			\$1,112,815	\$1,012

Hydrogen Peroxide	Amount	Unit cost	Annual cost	Per tonne of H2O2
Investment	\$56,812,533	3,200 \$/tpy	5,046,511	284
Variable Operating Costs:				
Hydrogen supply	63 kg/tonne	1.01 \$/kg	1,132,234	64
Other raw materials (chemicals)				60 - 100
Electricity	800 kWh/tonne		142,031	8
Electricity for steam	1305 kWh/tonne		231,649	13
Fuel for steam	Heating oil or Wood pellets	7.07 \$/GJ	142,141	8
	1.13 GJ/tonne	10.50 \$/GJ	211,006	12
Total Variable			Low	153
			High	197
Fixed Operating Costs:				
		Average		
Maintenance, material & labour	3.0% of H2O2 inv.		1,704,376	96
Labour	16 people	30000 \$/person	480,000	27
Supervision+Lab tech	8 people	35000 \$/person	280,000	16
Direct labour overhead	30% Labour+Sup		228,000	13
General plant overhead	65% Labour+Sup		494,000	28
Other (insurance, etc.)	1.5% of total inv.		932,552	53
Total fixed				232
Total Investment	\$62,170,131			
Total Production Costs			Low \$12,313,096	\$669
			High \$13,414,791	\$713

Table 26: Hydrogen Peroxide Production Costs for Scenario 3.

Process steam is partly produced from seasonal off-peak electricity and partly from a fuel.

5.3.4 Sensitivity Analysis

Capital investment is a key parameter to the total production cost of hydrogen peroxide. To investigate its relative influence, a sensitivity analysis is performed. The real rate of interests, the rate of electricity and the estimated costs of chemicals are also varied. The results of the analysis are presented in Figure 29. The minimum production cost for Scenario 3 is used as the base case with chemicals costs of \$60/tonne.

Looking at the variation of the total production cost with respect to investment levels, it can be seen that to bring the hydrogen peroxide production cost below the level of \$650/tonne, the initial capital investment must be lower than \$2800 per annual tonne capacity. In this case, the cost of producing hydrogen peroxide in Fort Smith approaches the range of existing producer costs.

Also evident from the sensitivity analysis is the strong influence of electricity rate. A low electricity rate is essential for the feasibility of establishing a hydrogen peroxide plant in the area.

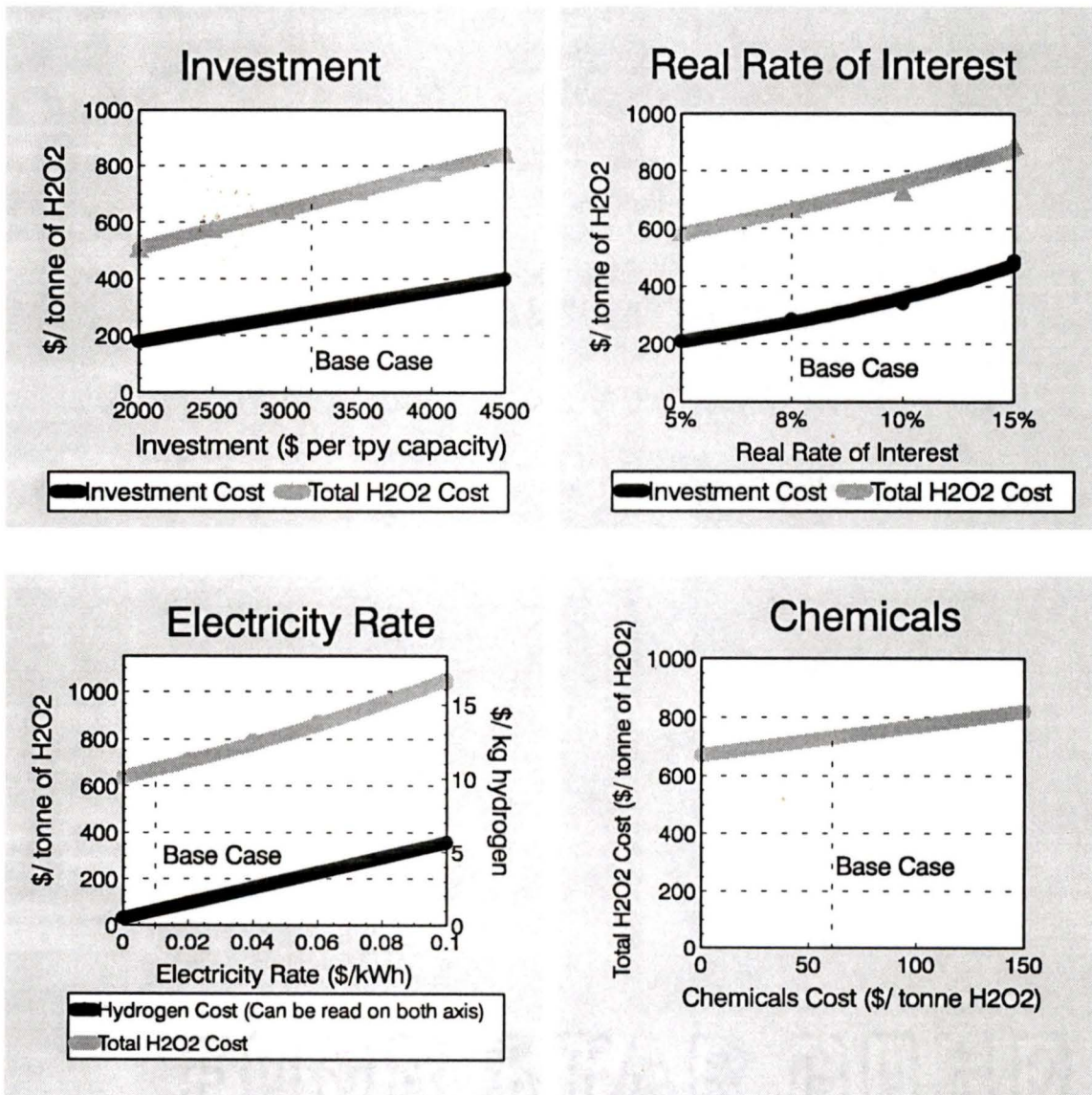


Figure 29: Sensitivity Analysis of Cost Parameters on Hydrogen Peroxide Total Production Cost. The base case parameters are taken from the minimum production cost of Scenario 3 and using a base case cost of \$60/tonne for chemicals.

5.4 Concluding Comments

A hydrogen peroxide production plant in the Fort Smith area, based on the industry standard anthraquinone process, is "not infeasible" although at the limit of economical viability.

A Fort Smith plant benefits from lower hydrogen and electricity supply costs than conventional producers, given a favourable electricity rate is applied. However, these benefits are more than offset by the poor economies of scale associated with the small scale of production. The anthraquinone process typically reaches economies of scale for plant capacities greater than 30 kt/year of hydrogen peroxide. Hydrogen supply levels required for such production quantities cannot be sustained by the present available excess electricity of the Taltson Dam.

In the present market conditions, substantial overcapacity is putting downward pressure on the market price of hydrogen peroxide. This, in combination with the relatively high production cost in Fort Smith, creates a small margin for return on investment. Therefore, the establishment of a hydrogen production plant in Fort Smith represents a high risk investment at the moment. However, a stable growth in demand will likely increase the market price of hydrogen peroxide and improve the prospects for a Fort Smith venture.

The feasibility of a hydrogen peroxide plant in Fort Smith not only depends on the relative production cost and market price but also on the characteristics of the target market. The location of the target market, the level of demand and the projected growth of this demand will all influence the economic viability of the project. Only a detailed market study will provide this information.

Chapter 6

Methanol

Methanol has traditionally been used as a solvent and as an intermediate in the production of a large number of chemical compounds, such as formaldehyde, acetic acid, and others. Methanol first entered the fuel market as an octane improver for unleaded gasoline, in the form of methyl *tert*-butyl ether (MTBE) or oxynol, a blend of methanol and MTBE. More recently, methanol has gained considerable interest as a fuel substitute for gasoline and diesel, or as a blend additive sometimes referred to as an extender of oil supply. Characteristics of methanol are presented in Appendix E along with gasoline and diesel.

Methanol has a high octane value and allows higher compression ratios than other conventional fuels, providing increased efficiency and improved power output per cylinder. As an oxygenated fuel, methanol has potential for lower carbon monoxide emissions. However, overall emission performance (NO_x , SO_x , etc.) is not dramatically improved over standard fuels. Problems related to methanol's corrosivity, large volume per unit energy, high autoignition temperature and poor cold start performance are gradually being overcome with improved technology [76,79,90,91].

Methanol as an energy currency may also be used as a turbine fuel for electricity generation. Also, research is being conducted for the use of methanol as a hydrogen carrier for fuel cell applications.

Methanol is currently manufactured worldwide by conversion of a synthesis gas, referred to as *syngas*, derived from natural gas, refinery off-gas, petroleum, coal or biomass. Producing methanol from biomass is particularly attractive in places where no natural gas or petroleum products can be found locally and a sufficient supply of biomass exists. It allows the production

of an indigenous liquid fuel, possibly used for transportation or electricity generation. Although no biomethanol plant operates on a commercial scale in North America today, this option is being revisited.

The state of Hawaii is one example [95]. Similar to the Northwest Territories, most of Hawaii's energy use (90%) is supplied by imported oil products. To lower the drain of dollars from the local economy, Hawaii has spent more than 10 years investigating the production, conversion and utilization of biofuels, in particular methanol from biomass. Researchers at the Hawaii Natural Energy Institute are presently studying small scale biomass gasification in order to assess the feasibility of large scale production of methanol for substitution into the transportation sector.

6.1 Production Overview

6.1.1 Biomethanol Process Description

Figure 30 illustrates the conventional process for the conversion of biomass to methanol.

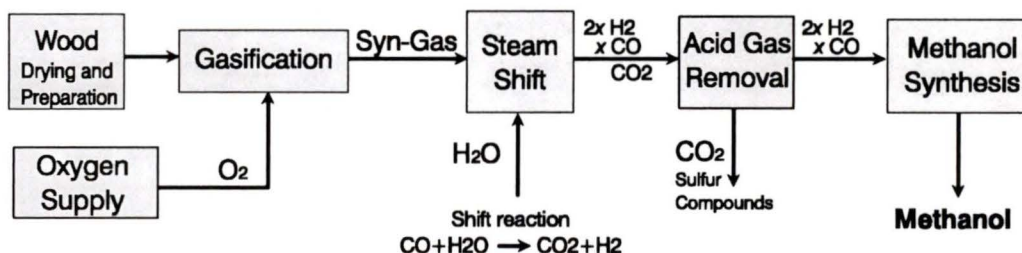
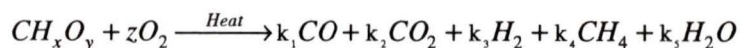


Figure 30: Conventional Biomethanol Production Process.

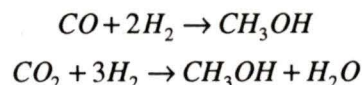
Biomass is reacted with oxygen (partially burned) in a gasifier to form a syngas containing carbon monoxide, carbon dioxide, hydrogen, water, small amount of methane, and entrained residual tar, char, and ash. The general gasification reaction is:



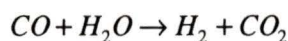
where x and y depend on the type of biomass, and z and k_i depend on the biomass type, the gasifier type and the operating conditions.

Water, methane and entrained residual tar, char and ash are not part of the methanol synthesis reaction and are removed at different stages in the process. Methanol (CH_3OH) is produced from

the synthesis gas by catalytically reacting hydrogen with carbon monoxide (CO) and carbon dioxide (CO₂), according to the reactions:



The syngas is deficient in hydrogen, due to the low hydrogen content of biomass. Consequently, the carbon monoxide reaction is preferred, since it requires less hydrogen per unit of methanol produced. In general, the syngas does not contain enough hydrogen to fully convert all the CO of the gas into methanol. To increase the methanol yield, water is added to the gas and the mixture is passed through a shift reactor where part of the excess carbon monoxide reacts with water in the presence of a catalyst to form hydrogen and carbon dioxide.



The maximum methanol yield occurs when a molar ratio of two H₂ to one CO is obtained.

CO₂ is removed, along with other acidic gases, through an acid gas absorber. The CO₂ is vented to the atmosphere.

In the Fort Smith project, hydrogen and oxygen are produced electrolytically and are available as external feedstocks for the production of methanol. With external hydrogen addition to the synthesis gas, the shift reaction is no longer necessary. Moreover, an external source of hydrogen increases the methanol yield per unit of wood used and decreases the carbon dioxide emissions.

6.1.2 Gasification Principles

Gasifiers are relatively simple devices. The mechanics of their operation, such as feeding and gas clean-up, are also simple. The successful operation of gasifiers, however, is not simple. The thermodynamics of gasifier operation is not well understood. Therefore, no neat rules exist to specify the relationship between feedstock properties, operation conditions and product characteristics. Gasifier performance must be obtained empirically.

Table 27 presents properties of biomass, charcoal and coal. Gasification of biomass is often explained using concept for gasification of coal. However, biomass contains a larger portion of volatile matter¹⁸ compared to coal, therefore gasification reactions differ.

	Most Wood	Pine Bark	Charcoal	Bark Char	Bituminous Coal	
					Low volatiles	High volatiles
Proximate analysis, wt%						
Volatile matter	74-82	73.4	20-30		18.0	38.6
Fixed carbon	16-23	25.9	50-70		77.6	58.6
Ash	0.5-3.5	0.7	2-20		4.4	2.8
Ultimate analysis, wt %						
Carbon	49-53	52.3	65-80	50.0	83.7	79.6
Hydrogen	5.8-6.7	5.8	2-3.5	4.0	4.6	5.5
Oxygen	35-44	38.8	11-18	24.5	5.7	9.8
Nitrogen	0.1-1.5	0.2	0.2-0.4	0.1	1.1	1.6
Sulfur	0-0.2	0.0	0.1-0.2	0.1	0.8	0.7
Ash	0.5-3.5	2.9	2-20	21.4	4.1	2.7

Table 27: Examples of Feedstock Analysis (dry basis) [89,97].

Any **thermal conversion** process for biomass involves some or all of the following processes characterized by the degree of oxygenation:

Pyrolysis: Biomass + Heat (No oxygen) → Gas, charcoal, oil vapours

Gasification: Biomass + Limited oxygen → Fuel gas

Combustion: Biomass + Stoichiometric oxygen → Hot combustion products

Pyrolysis is the breaking down (lysis) of a material by heat (pyro). It is always the first step in the combustion or gasification of biomass. When biomass is heated in the absence of air (oxygen) to about 350°C, it forms gases (CO, CO₂, H₂, H₂O, and CH₄), charcoal (C), and pyrolysis vapours from the volatile matter (≈CH_{1.2}O_{0.5}). The vapours contain hydrocarbons and

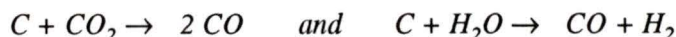
¹⁸ Matter easily converted into vapour.

wood tars which are gases at the pyrolysis temperature but condense to form a smoke composed of fine tar droplets as they cool.

Combustion of biomass is more complex than either pyrolysis or gasification since the biomass must first pyrolyze, then be partially combusted (gasified) before it is fully combusted in the presence of sufficient oxygen. Combustion releases an amount of heat that varies between types of wood. This amount of heat is referred to as the heating value of the fuel wood and is typically around 20 MJ/kg for most dry wood.

Gasification of biomass to produce synthesis gas can be summarized as follows:

- *Pyrolyzing the biomass:* This endothermic reaction (requires heat) produces gas (CO , CO_2 , H_2 , H_2O , and CH_4), carbon, and pyrolysis vapours.
- *Gasifying the carbon*¹⁹: Carbon produced from pyrolysis is gasified. Two important reactions for the gasification of carbon (also called char in the literature) are the Boudouard reaction and the Water-Gas reaction:



Carbon reacts with CO_2 and H_2O to produce the fuel gases CO and H_2 . Both these reactions require heat. They occur very rapidly at temperature over 900°C , and their heat consumption has a cooling effect on the surrounding gas.

- *Converting the pyrolysis vapours:* Vapours produced during pyrolysis are converted to stable gases, CO , H_2 and CH_4 . When the vapours cool down, they condense to produce tars and oils commonly known as creosote or soot. From the standpoint of methanol synthesis, tars are undesirable in the syngas since they would deteriorate the operating conditions of downstream devices. They are removed using filter or scrubber but this operation is costly. Depending on the gasifier design and operating temperature, converting them to gases can be accomplished either by high temperature cracking (above 800°C) or high temperature partial combustion (reaction with oxygen, releases heat). If the carbon gasification reactions occur in the vicinity of the pyrolysis vapours, the cooling effect of the carbon reactions might prevent the tars and hydrocarbons from being converted to gas.

¹⁹ Carbon is the name applied to a chemical element that occurs in dozens of physical forms, both pure (diamond, and graphite) or impure (coke, charcoal, soot, ...).

During the gasification process, CO and H₂ can react to form methane according to the reaction $CO + 3H_2 \rightarrow CH_4 + H_2O$. This exothermic reaction proceeds slowly below 900°C, unless a catalyst is present. The presence of methane (CH₄) in the syngas may or may not be suitable, depending on the application.

Finally, the characteristics of the biomass feedstock will influence gasification performance.

- At high temperature (900°C), ash melting and sintering can occur. This is a great concern for high ash content feedstocks since it can cause severe operating problems in some gasifiers, by affecting the uniformity of the reacting bed or plugging the grate.
- The moisture content of the biomass affects the quality of the gas produced. Energy must be subtracted from the heat budget of the gasifier for each kg of water that has to be vaporized and raised to pyrolysis temperature. It is desirable to dry the biomass prior to gasification stage to a moisture content lower than 20%.
- Particle size and shape, and feedstock bulk density are other important characteristics. Different type of gasifiers will have different requirements as discussed in the next section.

6.1.3 Technology Review

Gasifiers

Gasifiers are classified according to their heating mechanisms. Both pyrolysis and carbon gasification processes require heat. Heat is either generated internally (direct) or supplied to the gasification bed externally (indirect).

Direct heat generation is obtained by circulating sufficient oxygen inside the gasifier reactor to induce *combustion* of a portion of the biomass feedstock or in some cases the pyrolysis vapours. Oxygen, rather than air, must be used for methanol syngas production. If air were used, nitrogen could represent about 40% of the syngas composition and would result in high compression and recycle costs as well as undesirable side reactions and catalyst deactivation.

Indirect gasification utilizes external heat. The source of heat may be the external combustion of a portion of the biomass or any other available heat source. This gasification mechanism is otherwise known as *pyrolytic gasification* since no or very little oxygen is circulated through the

bed. This process may lower CO_2 concentration in the gas (no internal combustion) and usually increases methane concentration.

Gasifiers are also classified according to the reactor type. In a **fixed bed** (sometimes called moving bed) gasifier, biomass undergoes different gasification reactions in different zones within the reactor. Figure 31 presents an example of a particular fixed bed gasifier called downdraft gasifier because the oxygen and gas flow downward. The highest temperature occurs in the pyrolysis zone and is not influenced by the cooling effect of char gasification. This allows a high level of conversion of pyrolysis oil and tars. Heat from combustion of oil and tars maintain the pyrolysis reaction. Fixed bed gasifiers require uniform feedstock shape to avoid solid flow difficulties, such as channeling and bridging (sawdust or fibrous materials are not suitable).

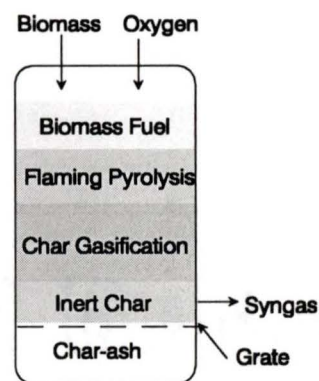


Figure 31: Diagram of a Fixed Bed Downdraft Gasifier.

In a **fluidized bed**, oxygen (or air) rises through a grate at high enough velocity to levitate the particles above the grate, thus forming a fluidized bed. The bed consists of a mixture of ash and biomass at different degrees of conversion. Drying, pyrolysis, char gasification and combustion all occur essentially simultaneously. The temperature is mostly uniform and usually kept low enough to avoid ash sintering but consequently the level of methane and oil tars may be greater.

In **entrained bed** gasification, fine particles of biomass in suspension are moved through a hot furnace. The entrained bed gasifier can produce a syngas which is low in hydrocarbons, oils, and tars, but extensive feedstock preparation is required.

Several different gasifiers have been tested, to varying extents, on biomass feedstock during the past decade. Table 28 gives a summary. The only gasifiers commercially available today are coal gasifiers, such as The Winkler, Lurgi and Koppers-Totzek systems. Coal gasifiers may present problems when used with biomass because of the lower density and higher volatile content of the feedstock. Gasifiers designed specifically for biomass feedstock have been built and tested. The principal barrier for commercialization of these biomass systems has been their relatively high syngas production cost in comparison with natural gas and coal based systems.

Table 28: Biomass Gasifiers.

	SERI ^a Fixed bed Stratified- downdraft	IGT ^b Fluidized bed	Univ. Missouri Indirect Fired fluidized bed [82]	Battelle Columbus Entrained bed [81]	Winkler Fluidized-bed [87,97]	Lurgi Circulating fluidized-bed [85]	Koppers-Totzek Entrained bed [87,97]
Stage of Development	> 10 dry tpd	~ 10 dry tpd	~ 1 dry tpd	~ 10 dry tpd	commercial/ coal	commercial/ coal	commercial/ coal
Mechanical Complexity	Simple	Moderate	Complex	Complex	Moderate	Moderate	Moderate
Gasification Medium	Oxygen	Steam,oxygen	Steam	Steam	Steam,oxygen	Air	Steam,oxygen
Heating Mechanism	Autothermal Oxygen-blown	Autothermal Oxygen-blown	Pyrolysis Internal bundle	Pyrolysis Heated sand	Autothermal Oxygen-blown	Autothermal Air-blown	Autothermal Oxygen-blown
Temperature, °C	800-1100	980	700	775	870	820	980
Pressure, bars	atm.	34.5	atm.	1.5	8.1	atm.	atm.
Oxygen,kg/kgdry wood	0.38	0.3	0	0	0.46	0	0.56
Steam, kg/kg dry wood	0	0.3	1.5	0.61	0.18	0	0.03
Target Fuel Size (cm)	~ 1-5	< 5	< 5	< 5	< 5	< 5	< 0.2
Gas Composition % (vol.) mol							
Hydrogen	27.82	20.80	19.98	11.57	18.20	17.54	28.70
Carbon Monoxide	34.71	15.00	39.96	25.67	13.60	21.50	35.27
Carbon Dioxide	12.99	23.90	19.98	6.14	25.70	9.82	15.17
Methane	4.09	8.19	12.96	8.66	10.50	2.72	0.20
Water Vapour	20.39	31.80		44.17	31.90	12.28	20.55
Nitrogen	0	0		0.44	0	35.43	0.11
Inerts	0	0.31	7.02	3.31	0.10	0.71	
Tar, kg/kg dry wood	0.005	0.011	0.08	0.01			
Char, kg/kg dry wood	0.06		0.06		0.007		
Carbon conversion to gas, %	95	96	70-90	> 90	95	98	

a Solar Energy Research Institute, now the National Renewable Energy Laboratory, Golden Colorado [88,89]

b Institute of Gas Technology, Chicago [80]

The SERI downdraft gasifier or the IGT fluidized bed gasifier both present advantageous characteristics for biomethanol production in Fort Smith. Both gasifiers have been tested and have proven good performance. The downdraft gasifier has been designed specifically to produce low oil and tar syngas, well suited for methanol synthesis. The fluidized-bed gasifier is much less sensitive to feedstock characteristics. This may be an advantage in the case of Fort Smith where biomass is likely to vary in composition and shape.

The University of Missouri and Battelle Columbus gasifiers do not appear well suited for the case of Fort Smith. These gasifiers use steam rather than oxygen and produce high heating value gas by pyrolysis gasification. In the case of methanol synthesis, heating value is not an essential criteria and does not justify the higher complexity of these gasifiers.

Methanol Synthesis Reactors

The technology for converting syngas into methanol is well established. The two most common low pressure methanol synthesis reactors are those of ICI and LURGI. The methanol synthesis reaction is exothermic, generating heat. The efficient recovery of the heat of reaction is crucial to the process economics. The method of heat recovery constitutes the major difference between these two systems. ICI uses reaction heat for boiler feedwater heating while the LURGI uses the heat of reaction for raising process steam. The LURGI system is more efficient.

6.2 Analysis

6.2.1 Biomass Feedstock Options in Fort Smith

The Stanley study for the establishment of a wood pellet plant in Fort Smith investigated different biomass feedstock supply options for the pellet plant [92]. The alternatives included wood residue from sawmills in Hay River or Northern Alberta as well as in-forest green wood chipping. These options also apply to the biomethanol plant.

Another possibility is the use of partly burnt residual wood from forest fires. The important criteria for the production of methanol synthesis gas is not so much the high heating value of the fuel as the carbon content. During a fire, the external part of the tree undergoes combustion and is reduced to char-ash and ash. Depending on the temperature attained, part of the biomass not in contact with oxygen is pyrolyzed and reduced to charcoal. The core of the tree may be unpyrolyzed dry wood.

Burnt wood could have advantages for gasification purposes. First, the average moisture content could well be below 15%, thus reducing drying costs. The low volatiles content of charcoal and char could reduce the level of tar production. A very gross approximation of the wood composition resulting from a fire can be found by looking at bark char, charcoal and wood compositions in Table 27 (page 93).

Burnt wood could also be problematic. The mixture of char with unpyrolyzed biomass may favour an overall reaction temperature in the gasifier too low for the residual tar conversion. Another important problem resides in the high ash content of the combusted and pyrolyzed portions. If the ash fusion temperature is lower than the operating temperature, slagging and sintering may happen causing different operating problems for different types of gasifiers. This can be partly overcome by sacrificing the combustion residue surrounding the trunk.

The availability of burnt wood within 100 km²⁰ around Fort Smith has been estimated with the assistance of the South Slave Research Centre and the Fort Smith Department of Renewable Resources, Forestry Division. The Little Buffalo Woodlot #2, covering about 880 hectares,

²⁰ In general, in-forest chipping operations is considered economical within a 100 km radius from the user. [37]

located 50 km West of Fort Smith along Highway #5, is the only accessible burnt area outside Wood Buffalo National Park. The area resources have been estimated from a partial survey following the fire. The estimates indicate an average wood volume of 77 m³ (34 cords) per hectare. The burned resource is, however, over 10 years old, falling down and disintegrating rapidly. According to the area forester, current volumes are probably 30% to 40% those obtained at the time of the survey. Jack Pine wood type occupies most of the area. 20% moisture pine fuel wood weighs about 1.2 tonne per cord. Burnt wood weighs much less, due to evaporation of moisture and volatile matter. Assuming burnt wood represents between 50% and 70% the weight of fuel wood, the total amount of burnt wood available today, in this specific area, varies between 5,400 and 10,000 tonnes.

Table 29 presents a summary of the possible feedstock supply options.

Source	Availability ^a	Moisture Content %	Delivered Costs ^{a,b} \$/tonne	Delivered Costs ^f \$/dry tonne
Patterson Sawmill, Hay River	4,000 tonnes/year	40%	3.50 ^c	5.83
High Level Forest Products Sawmill, Alberta	Undetermined	40%	12.00 ^d	20.00
In-forest green wood chipping	Undetermined	40%	48.00 ^e	80.00
In-forest burnt wood chipping	5,400-10,000 tonnes	15%	48.00 ^e	56.50

^a total weight, including moisture

^b adjusted for Fort Smith: transportation at 1.2 cents/tonne-road km, 3.4 cents/tonne bush km

^c assume zero cost supply, 280 road km

^d supply at 7\$/tonne, 400 road km

^e processing 46\$/tonne, average 50 bush km

^f 100% dry weight is used as a common basis for comparison.

Table 29: Feedstock Options for a Biomethanol Plant in Fort Smith.

6.2.2 Plant Description

Based on the technology overview, the SERI downdraft gasifier and the LURGI methanol reactor are selected for the analysis. Typical syngas properties from the downdraft gasifier are given in Table 28. Since actual operating performance for a specific feedstock and gasifier can only be obtained empirically, the data in Table 28 is used in this analysis. The SERI gasifier was also

selected for a number of biomethanol plant feasibility studies providing good estimates of economic data.

The Stone and Webster study [94] is of particular interest since it investigated a small scale biomethanol plant with two important design philosophy criteria: 1) all processing equipment selected is commercially available, except for the gasifier and 2) energy integration is optimized to avoid importing supplementary fuel. The Hawaii Natural Energy Institute research [78,83,86] is also relevant since it looks closely at the addition of external hydrogen to increase the methanol output per unit of biomass used. The plant described in this section is an adaptation of the facilities detailed in these reports.

Wood chips are delivered to the plant, weighed and dumped onto a storage pile that holds about seven days' supply of wood. Wood chips are fed to the sizing equipment where tramp iron and stones are removed, oversize wood is reduced in size, and undersize wood is removed for use as auxiliary fuel. Acceptable wood is then dried, if necessary, to about 17% moisture and fed to a 24-hour capacity storage silo.

During gasification, about 95 percent of the carbon content in the wood is converted to syngas in the form of carbon monoxide, carbon dioxide and methane. The remaining is in the form of ash, tar and char. Char is kept for later use as an auxiliary fuel. Although the final weight of the ash residue can be lower than 5% of the biomass weight, it may occupy up to 20% of the original biomass volume. Adequate removal of this bulky material is important. Ash may be used as a soil conditioner.

The gas is passed through a steam generating cooler and cooled to about 40°C. It is then washed with water in a venturi scrubber to remove particulates and tars and to condense water prior to compression. Washing water is treated to remove particles, insoluble oils, and tars which are burned as auxiliary fuel. Clean water is then recirculated to the scrubber.

The gas is compressed to about 25 bars (365 psi) to improve the efficiency of acid gas removal. Heat exchange with boiler feedwater further cools the gas. The amount of CO₂ not required in the methanol synthesis reaction is removed in the acid gas absorber along with sulfur compounds which poison the methanol synthesis catalyst. Hydrogen sulfide is removed from the acid gas mixture by adsorption/oxidation on sponge iron oxide. The syngas is then compressed to

methanol reaction pressure and passed through a second stage of sulfur removal at high temperature. Next, compressed hydrogen is added.

The syngas is converted to methanol in the presence of a catalyst. The operating temperature and pressure in the Lurgi methanol reactor are 225-250°C and 55-83 bars respectively. Raw methanol pressure is reduced to 4 bars and all gases are removed. Water is removed in a distillation column. Overall, 99.7% of the methanol is recovered. If methanol is to be used as a fuel-blending agent, as in gasoline for example, water and non-condensable gases need to be removed from the methanol. If the product is to be used as a neat fuel, little or none of the water needs to be removed.

Facilities are provided for wastewater treatment and disposal, boiler feedwater supply, steam generation at three pressure levels, waste incineration and cooling water supply.

The energy requirement for steam generation is provided by the combustion of residual, char, tar and methane extracted at different stages in the process as well as recovery of process heat from the methanol reactor. Steam is required mostly for wood drying, acid gas removal and methanol purification. The major portion of the electricity requirements goes to syngas compression, the remaining to ancillaries. Total electricity consumption is estimated at 320 kWh per tonne of methanol output [83,87,94,97].

6.2.3 Scenario Development

The analysis will look at two scenarios. In the first scenario, all the carbon oxides are converted to methanol. The right amount of wood is gasified to obtain a balance between the carbon oxides in the syngas and the total hydrogen, both electrolytic and from the syngas. The amount of wood gasified in this case uses less than half the amount of oxygen from the electrolyser. The amount of wood required per unit of methanol produced is minimum and no carbon dioxide is emitted. Figure 32 presents a mass balance of the principal constituents for this scenario normalized to one tonne of electrolytic hydrogen.

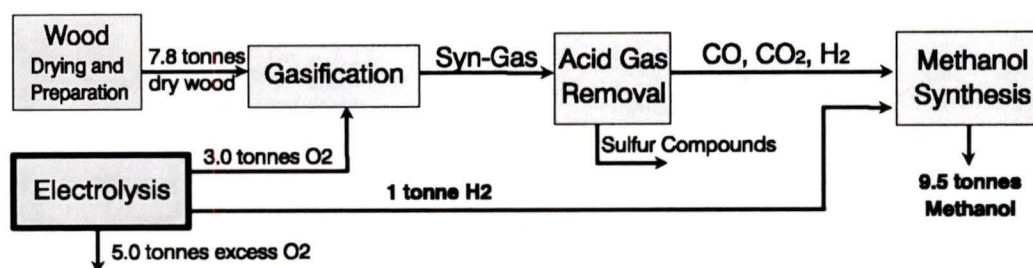


Figure 32: Scenario 1: Complete conversion of Carbon Oxides.
Wood mass is presented on a 100% dry basis.

The second scenario (Figure 33) makes use of all the oxygen available from the electrolysis plant. In this case, a larger amount of wood is gasified giving a larger amount of CO and CO₂. Not enough hydrogen is available to convert all the carbon oxides therefore part of the CO₂ is scrubbed and vented. However, because most of the hydrogen is used by the CO reaction, rather than the more demanding CO₂ reaction, more methanol is produced. In summary, more wood is used per unit of methanol produced but more methanol is produced per unit of hydrogen available. Depending on the relative costs of wood and hydrogen, this scenario may benefit from economies of scale.

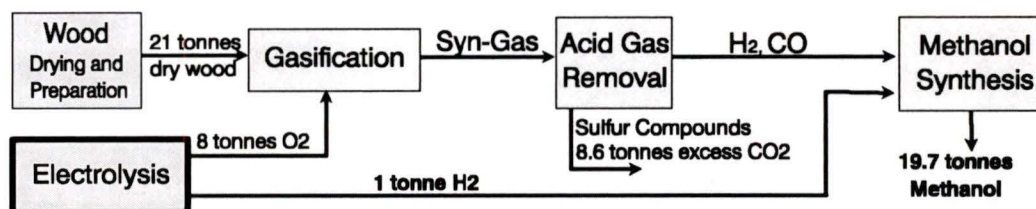


Figure 33: Scenario 2: Full Oxygen Utilization.
Wood mass is presented on a 100% dry basis.

6.2.4 Production Plant Capacity

The amount of methanol produced depends on the amount of hydrogen and oxygen available, which in the case of Fort Smith, depends on the total amount of power available and the amount of electricity used by the methanol plant. Gasification and methanol synthesis processes offer optimum performance when performed at constant flow rate. For this reason, an overall plant capacity of 8.5 MW is considered. Table 30 quantifies the annual methanol production for each scenario.

Making use of all the oxygen produced from electrolysis almost doubles the methanol production capacity. However, by doing so, the consumption of wood is more than doubled and the plant produces carbon dioxide emissions.

tonnes/year	Complete Conversion of Carbon Oxides	Full Oxygen Utilization
Methanol production	12,210	23,900
Hydrogen production	1,290	1,210
Oxygen production	10,320	9,680
Dry wood consumption ^a	10,100	25,540
Excess oxygen	6,473	
Excess CO ₂		10,460

a Given as 100% dry basis. The delivered amount of wood = dry amount / (1 - %moisture content)

Table 30: Annual Methanol Production for Both Scenarios.

6.2.5 Economic Analysis

The **investment** cost was derived from data presented in a number of studies [83,94,97,98]. Component characteristics are adapted to meet the requirements and scale of the proposed scenarios. Costs figures are expressed in Canadian dollars of 1993 prices and exchange rates. The estimated installed capital cost (excluding electrolyser) are 13 and 23 MM\$ for Scenario 1 and 2 respectively. The plant lifetime is 20 years. A real rate of interest of 8% is applied.

Variable operating costs include raw material requirements, wood, hydrogen, oxygen, catalysts and chemicals as well as energy requirements. An average of \$70 per tonne of dry wood is assumed. Several alternatives exist for both the source and the moisture content of wood supply. To account for different alternatives, a wide range of wood supply cost is considered in the sensitivity analysis. For convenience, all the costs of electrolysis are charged to hydrogen, setting oxygen costs to zero. Supervision and maintenance of the electrolysis plant are integrated to the methanol plant, leaving capital and electricity as the components of hydrogen costs.

Fixed operation costs include operation labour and supervision, maintenance material and labour, and overhead expenses. These items are considered independent of the plant operating rate.

Table 31 and 32 summarize all basic assumptions and results of the analysis for both scenarios. Scenario 2 exhibits lower production costs. This advantage is due in part to economies of scale, reflected by lower investment and fixed operating costs.

Scenario 2 is also favoured in terms of its utilization of raw materials. Hydrogen (and indirectly oxygen) contributes to a significant portion of the total methanol cost in both scenarios. By using all the oxygen from the electrolyser, Scenario 2 produces more methanol and consequently reduces the cost contribution of electrolysis per unit of methanol produced. Although Scenario 2 uses more wood per unit of methanol output, the impact of wood is less significant than that of electrolysis on the total methanol production costs.

The annual production and total production costs of methanol for each scenario are presented in a number of different units in Table 33 for comparison purposes.

Scenario 1: Complete Conversion of Carbon Oxides

Methanol Production Costs

Electricity Rate	0.01 \$/kWh
Real Rate of Interest	8%
Onstream Time	94.5%
Plant Lifetime	20 years

Annual Production of Methanol	12,210 tonnes/year
Annual Production of H ₂	1,289 tonnes/year
Annual Dry Wood Consumption	10,102 tonnes/year
Excess O ₂	6,473 tonne/year
Installed Electric Power Requirements	8.51 MW

Hydrogen	Amount	Unit cost	Annual cost	Per tonne of H ₂
Electrolyser	34 cells			
	or 6,418 kW (nominal)			
	or 8,033 kW (max)			
Investment	\$6,008,705	\$936 \$/kW (nom)	612,000	475
Average Electricity	51.59 kWh/kg		664,972	516
Operation	Labour and maintenance included with methanol production			
Total			\$1,276,972	\$991

Methanol	Amount	Unit cost	Annual cost	Per tonne of methanol
Investment	\$12,975,821	1,063 \$/tpy	1,321,616	108
Variable Operating Costs:				
Wood (dry),	0.83 tonne/tonne	70 \$/dry tonne	707,156	58
Hydrogen supply	106 kg/tonne	0.99 \$/kg	1,276,972	105
Electricity	320 kWh/tonne		39,071	3.20
Other manufacturing costs	1.85 \$/tonne CH ₃ OH			1.85
Total Variable			2,023,199	168
Fixed Operating Costs:				
Maintenance, material & labour	3.0% of methanol inv.		389,275	32
Labour	16 people	28000 \$/person	448,000	37
Supervision	4 people	35000 \$/person	140,000	11
Direct Labour overhead	30% Labour+Sup		176,400	14
General plant overhead	50% Labour+Sup		294,000	24
Other (insurance, etc.)	1.5% of total inv.		284,768	23
Total fixed			1,732,443	142
Total Investment	\$18,984,526			
Total Production Costs			\$5,077,257	\$418

Table 31: Production Costs of Biomethanol for Scenario 1: Complete Conversion of Carbon Oxides.

Scenario 2: Full Oxygen Utilization

Methanol Production Costs

Electricity Rate	0.01 \$/kWh
Real Rate of Interest	8%
Onstream Time	94.5%
Plant Lifetime	20 years

Annual Production of Methanol	23,897 tonnes/year
Annual Production of H ₂	1,213 tonnes/year
Annual Dry Wood Consumption	25,540 tonnes/year
Excess CO ₂	10,458 tonnes/year
Installed Electric Power Requirements	8.49 MW

Hydrogen	Amount	Unit cost	Annual cost	Per tonne of H ₂
Electrolyser	32 cells or 6,041 kW (nominal) or 7,560 kW (max)			
Investment	\$5,757,884	\$953 \$/kW (nom)	586,453	483
Average Electricity	51.59 kWh/kg		625,871	486
Operation	Labour and maintenance included with methanol production			
Total			\$1,212,324	\$969

Methanol	Amount	Unit cost	Annual cost	Per tonne of methanol
Investment	\$23,081,395	966 \$/tpy	2,350,891	98
Variable Operating Costs:				
Wood (dry),	1.07 tonne/tonne	70 \$/dry tonne	1,787,853	75
Hydrogen supply	51 kg/tonne	0.97 \$/kg	1,175,521	49
Electricity	320 kWh/tonne		76,469	3.20
Other manufacturing costs	1.85 \$/tonne CH ₃ OH			1.85
Total Variable			3,039,843	129
Fixed Operating Costs:				
Maintenance, material & labour	3.0% of methanol inv.		692,442	29
Labour	20 people	28000 \$/person	560,000	23
Supervision	5 people	35000 \$/person	175,000	7
Direct Labour overhead	30% Labour+Sup		220,500	9
General plant overhead	50% Labour+Sup		367,500	15
Other (insurance, etc.)	1.5% of total inv.		432,589	18
Total fixed			2,448,031	102
Total Investment	\$28,839,279			
Total Production Costs			\$7,838,765	\$330

Table 32: Production Costs of Biomethanol for Scenario 2: Full Oxygen Utilization.

	Scenario 1		Scenario 2	
Units	Annual Production	Cost \$/Unit	Annual Production	Cost \$/Unit
Litres	15,416,209	\$0.33	30,172,565	\$0.26
Imp gallon	3,391,159	\$1.50	6,637,168	\$1.19
US gallon	4,072,975	\$1.25	7,971,616	\$0.99
GJ (LHV)	244,193	\$20.88	477,933	\$16.49
MMBtu (LHV)	231,462	\$22.03	453,017	\$17.40
Litre equivalent diesel (LHV)	6,681,060	\$0.76	13,076,154	\$0.60
Litre equivalent gasoline (LHV)	7,399,780	\$0.69	14,482,831	\$0.54

LHV = Lower Heating Value

Table 33: Annual Production and Specific Production Costs.

Other biomethanol production costs obtained from the literature [83,87,88,94,96,97] vary between \$0.17 and \$0.35 per litre. The variation in costs is due to different technologies, different plant capacities and different cost figures for capital, wood supply, oxygen supply, electricity, etc. The lower end of this cost range represents the minimum foreseeable cost for biomethanol production. It corresponds to a plant capacity of 2 billion litres per year, 70 times larger than the plant in Scenario 2, using scale-up estimates for gasification technology still in development stages. The upper limit of this cost range is also associated with large scale production but is adversely affected by an external addition of hydrogen produced electrolytically from geothermal electricity at 5.6¢/kWh. The production costs in Fort Smith vary between \$0.26 and \$0.33 per litre, falling between the extremes presented in the literature. Fort Smith methanol production loses from economies of scale but benefits from low hydrogen and oxygen costs.

The market price of methanol is \$0.143 per litre, fob Edmonton, based on an annual contractual volume of 800,000 to 1,000,000 litres, for a three to four year period. Shipment by rail to Hay River adds about 4 cents per litre of methanol [Canadian National Railways]. Handling in Hay River and transportation to Fort Smith may add an additional 3¢ to 5¢ per litre, based on transportation costs of heating oil currently delivered to Fort Smith [Esso Edmonton]. Consequently, the market price of methanol in Fort Smith varies between \$0.21 to \$0.23 per litre. Even in the best case scenario, the production cost of biomethanol in Fort Smith, which does not include a profit margin for return on investment, exceeds the market price of methanol.

6.2.6 Sensitivity Analysis

The sensitivity analysis examines the influence of a number of parameters on the production cost of methanol. These parameters include plant investment (excluding the electrolyser), real rate of interest, electricity cost and wood supply cost. Figure 34 illustrates the results of the sensitivity analysis.

Methanol plant investment and wood supply cost have a significant influence on the total cost of methanol. Electricity rate also has a strong impact on total methanol production cost by influencing the cost of hydrogen supply. Taken individually, no realistic variation of these parameters sufficiently reduces the methanol production cost below the market price.

Only a favourable combination of plant parameters will yield production costs which break even with the current market price for methanol. A utility-owned methanol production plant could be such a circumstance. Such a plant would exhibit lower overhead expenses, would benefit from minimal electricity rates and apply a lower interest rate. Setting overhead expenses at 20% of labour and supervision salaries, electricity rate at 0.15¢/kWh (corresponding to the marginal production cost of the excess electricity) and using a real rate of interest of 5%, the methanol production costs become \$0.25 and \$0.21 per litre for Scenario 1 and Scenario 2, respectively. This configuration breaks even with the current market price.

However, the break-even basis operation does not apply to all utilization scenarios. For example, if methanol is to be used in the Hay River area or shipped via Hay River, transportation between Fort Smith and Hay River adds to the total cost of biomethanol. Moreover, the market price of methanol in Hay River is lower than in Fort Smith, making break-even cost more unlikely to attain. For such a case, the viability of the methanol production plant in Fort Smith is compromised.

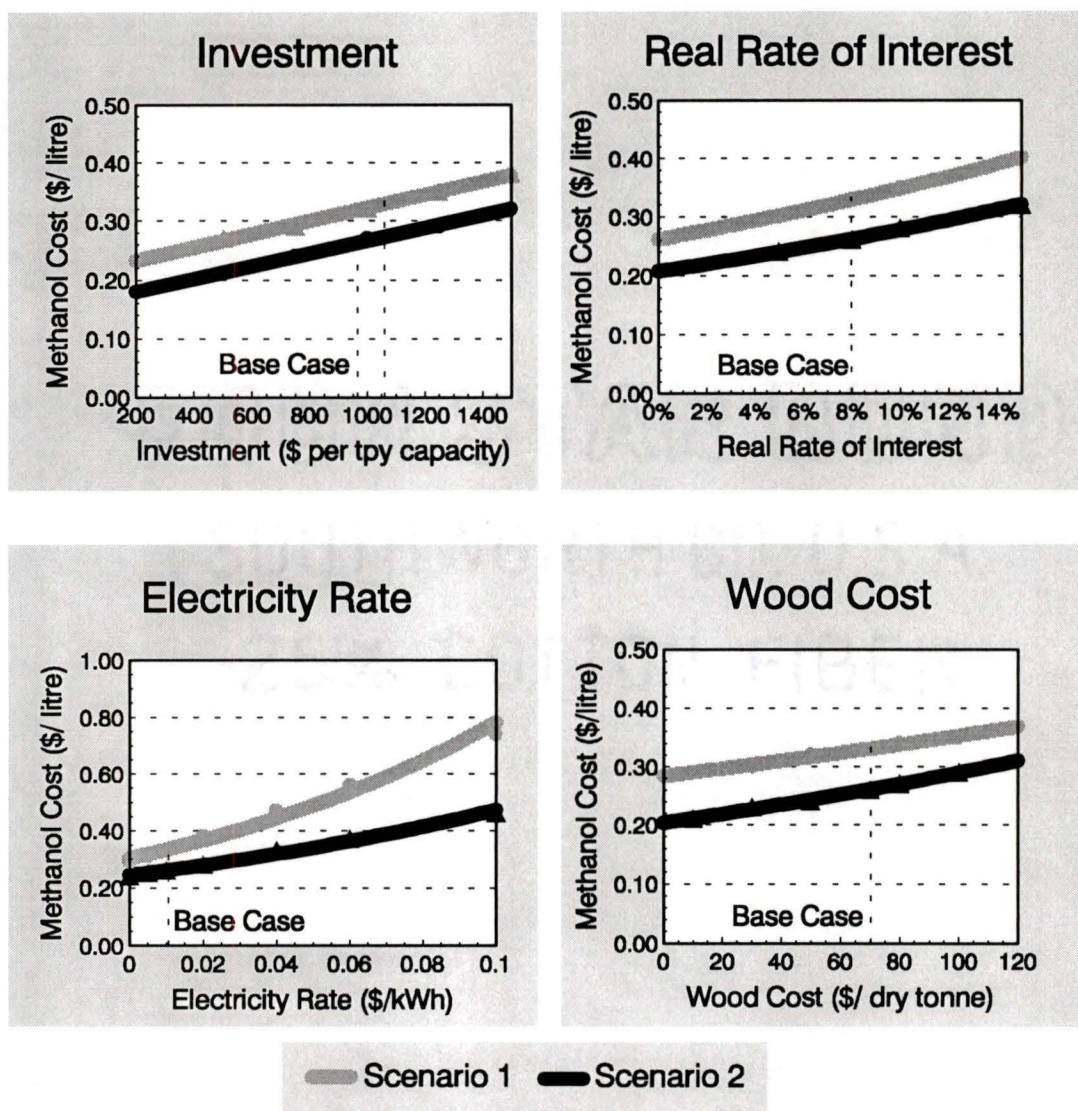


Figure 34: Sensitivity Analysis of Cost Parameters on Biomethanol Total Production Cost.
 Scenario 1: Complete Conversion of Carbon Oxides
 Scenario 2: Full Oxygen Utilization

6.3 Concluding Comments

The preliminary evaluation already shows that the option of producing biomethanol in Fort Smith to utilize the excess capacity of the Taltson Dam via electrolytic hydrogen and oxygen is economically unattractive. This is illustrated in Figure 35 where the production cost of methanol in Fort Smith exceeds the current market price of imported methanol.

Given favourable plant costs parameters, a biomethanol plant could operate on a break-even basis with the market price. An example of this is a utility-own plant which benefits from minimal electricity rate, lower interest rate and overhead expenses. However, the break-even basis operation applies only to certain methanol utilization scenarios.

In addition to the capability for methanol produced in Fort Smith to compete with merchant methanol, the biomethanol option feasibility also requires the evaluation of:

- The specifics of the methanol market, such as the location, the size and the application (electricity generation or transportation fuel).
- The long term reliability of wood supply.
- The capability for methanol to compete against the fuels it is intended to displace, such as gasoline or diesel.

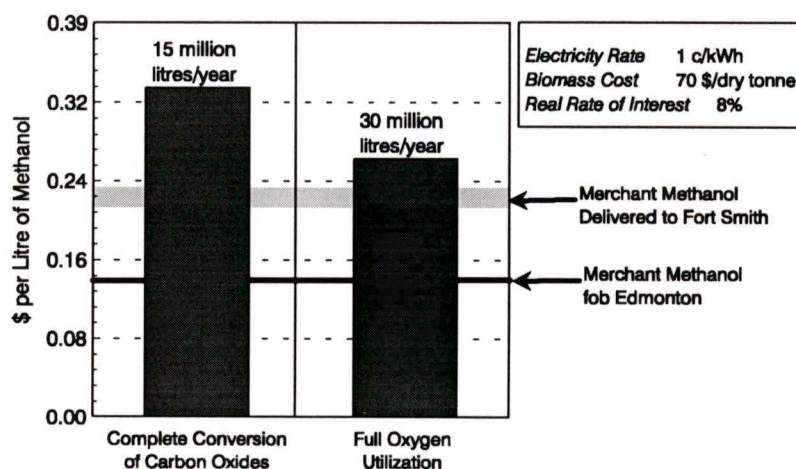


Figure 35: Comparison of Biomethanol Produced in Fort Smith with Methanol Market Prices.

Chapter 7

Fort Smith Project Conclusions

This study examined the potential of establishing a new hydrogen based industry to utilize the excess generating capacity of the Taltson Dam. The study shows that given favourable electricity rate, electrolytic hydrogen can be produced at a competitive cost compared to other production facilities in North America. Low cost hydrogen production in Fort Smith represents an opportunity for the community to develop a local industry based on this raw hydrogen gas.

The following recommendations were made to the steering committee in the Northwest Territories:

- *Of all options examined, hydrogen peroxide production is the most promising and attractive.* Hydrogen peroxide represents the largest local value added i.e., contributes most to local economic growth through jobs creation and collateral benefits. There is a nearby market for hydrogen peroxide with potential for increasing demand. A production plant can be configured to utilize a significant portion of the excess capacity of the Taltson Dam.
- *A detail market study should be performed to complete the investigation of project pre-feasibility.* In particular, it is imperative to clearly assess the nearby pulp and paper industry needs for hydrogen peroxide. Knowledge of both current consumption and trend for future growth of demand are essential for the following step.
- *Identifying and attracting investors constitutes the following step.* Existing producers represent the most probable investors, since they can provide technology and experience. The common opinion among producers at the moment does not favour new investment in the short term. However, if favourable operating and market conditions exist in the region, interest should come along.

The results of the study have been reviewed by the steering committee in the NWT as well as by the Electrolyser Corporation Ltd. The steering committee decided worthwhile pursuing the investigation for hydrogen peroxide. They envisioned a consortium of investors, and will possibly seek government funding to increase the rate of return on investment for private investors. Furthermore, the Electrolyser Corporation have already offered their assistance in identifying the interests of existing hydrogen peroxide producers.

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PART IV

GENERAL CONCLUSIONS

Chapter 8

General Conclusions

This section makes general observations concerning the synergies between hydrogen and excess hydroelectricity in remote areas. In particular, this section identifies opportunities and barriers associated with both remote hydroelectricity and hydrogen endeavours.

Many remote areas of Canada have hydroelectric sites with excess capacity. The number of these sites is likely to increase due to depletion of mines or closure of industries for which the generating capacity was originally built. Remote regions also often have significant still unexploited hydroelectric potential. The Taltson Dam is one example. Its capacity could be doubled without negative environmental impact²¹. In most cases, however, these local energy resources remain unexploited because of a distance barrier. It is economically impractical to link the electrical energy source to the potential end-users using conventional distribution technology.

Hydrogen is a means for storing and transporting the energy of non-fossil energy sources and, therefore, represents an opportunity for remote areas to take advantage of the local hydroelectric energy resources. Hydrogen is produced by electrolysis using electricity and water, both readily available at hydro sites. As shown in the Fort Smith study, production of hydrogen from excess electricity is feasible both technically and economically.

Figure 36 illustrates three possible utilization pathways for hydrogen from remote excess hydroelectricity. Each pathway includes a non-exhaustive list of examples.

²¹ An additional 20 MW would cost about 20 million dollars. Using the NWT Power Corporation economic assumptions (discount rate of 7.7%, lifetime of 60 years, load factor of 95%), adding running costs of 0.15 cents/kWh, the production costs of electricity is 1.1 cent/kWh.

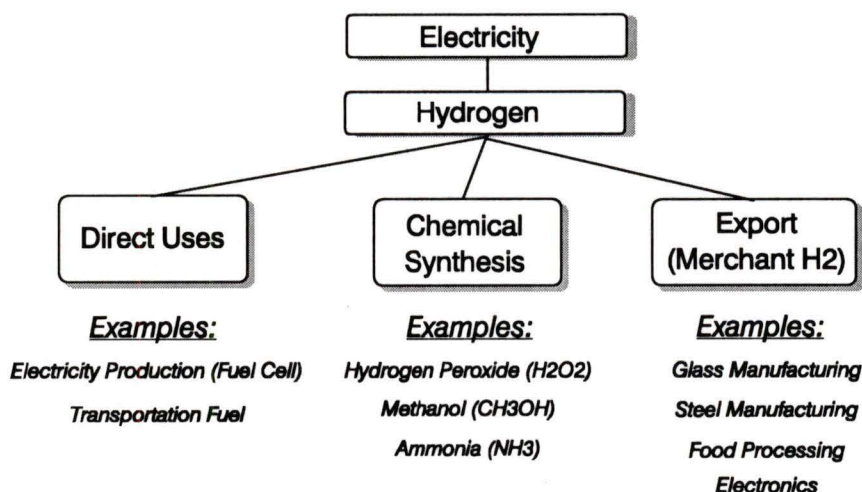


Figure 36: Pathways for Hydrogen from Remote Excess Hydroelectricity

Hydrogen can be sold as a commodity on the merchant market, either as compressed or liquefied hydrogen, or be used in the production of hydrogen-based chemical commodities. In unique circumstances, a hydrogen or hydrogen-based commodity may find a market nearby - such as hydrogen peroxide in the case of Fort Smith. However, in general, the option of exporting a commodity will suffer from high transportation costs due to the large distance barrier associated with remote areas.

On the other hand, hydrogen as an *energy currency* could *benefit* from the large distance barrier associated with remote areas. Remote regions are better positioned than southern regions to introduce hydrogen as a regionally "domestic" energy currency because of higher costs associated with importing conventional fuels. Therefore, in the long term, the most promising option for remote regions is using hydrogen directly in communities either for transportation purposes or the production of electricity.

Near-term direct uses of hydrogen are precluded, which results from the high capital cost barrier of hydrogen end-use technologies. Today, development of hydrogen end-use technologies is focused on maximizing efficiency, usually resulting in high capital cost. In cases of an unutilized (basically free) energy source such as excess hydroelectricity, efficiency is not a dominant issue. Therefore, there is a need for medium efficiency/low capital cost hydrogen end-use technology. This could be an important opportunity for Canada's hydrogen technology industries. Not only would medium efficiency/low capital cost hydrogen technologies serve the

development of remote regions of Canada, but these same technologies could be of interest to developing countries.

The broad conclusions may be itemized as follow:

- In many cases, hydroelectric resources in remote areas of Canada remain unexploited because of a distance barrier.
- Hydrogen is a means for storing and transporting energy harvested from non-fossil energy sources and, therefore, represents an opportunity for remote areas to take advantage of the local hydroelectric energy resources.
- Hydrogen can be sold as a *commodity* on the merchant market, or used in the production of hydrogen-based chemical commodities. However, in general, the option of exporting a hydrogen or hydrogen-based commodity will suffer from high transportation costs due to the large distance barrier associated with remote areas.
- In the long term, the most promising option for remote regions is using hydrogen as an *energy currency* directly in communities either for transportation purposes or the production of electricity.
- Near-term direct uses of hydrogen in remote communities are precluded by the high capital cost barrier of hydrogen end-use technologies.
- In conclusion, there is an immediate need and business development opportunity for manufacturing medium efficiency/low capital cost hydrogen end-use technologies. These technologies would serve well the development of remote regions of Canada and could even be of interest to developing countries.

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Personal Communications:

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101. B.C. Research Institute, Vancouver, Gordon Espelin.
102. Bellis & Morcom, Chicago.
103. Bowers, Ontario.
104. Canadian National Railways, Hay River and Edmonton.
105. Canadian Pulp and Paper Association, Montréal, Québec.
106. Chemprox, Bécancour, Québec.
107. CP Industries, Pittsburgh, PA, Bill Thomas.
108. Degussa Corporation, Ridgefield Park, New Jersey.
109. Du Pont, Wilmington, Delaware.
110. Du Pont Canada Inc., Gibbons, Alberta.
111. Du Pont Canada Inc., Head Office, Mississauga, Ontario.
112. Esso Petroleum Canada, Fort Smith and Edmonton.
113. Fiba Leasing, Boston, Massachusetts, Chris Adams, Frank Fin.
114. FMC, Prince George, British Columbia.
115. Government of the Northwest Territories Petroleum Product Division.
116. Horton CBI Ltd., Fort Saskatchewan, Alberta, Mark A. Stobart, Vice President, Western Sales Manager.
117. Huron Technologies Inc., Kingston, Ontario, Dennis F. Dong, Research Director.
118. Hydrogenal, Liquid Air Hydrogen Liquefaction Plant, Bécancour, Québec.
119. Le Centre de recherche en pâtes et papiers, Université du Québec à Trois-Rivières.

120. Linde, Vancouver.
121. Minnesota Valley Engineering, New Prague, Minnesota, Dave Hahn.
122. Northland Utilities (NWT) Ltd., Hay River, Steve Savage.
123. Northwest Territories Power Corporation, Hay River, NWT, George Sturge, Vice President Operations, Paul Vassilev, Engineer.
124. Northwest Territories Renewable Resources, Fort Smith District, Area Forester.
125. Norwalk Company Ltd., South Connecticut, Mario Perrotta, Sales & Marketing.
126. Process System International, Westborough, Massachusetts, Thomas Ankermann, Sales Manager, Cryogenic Systems Division.
127. Rix Industries, Oakland, California, Rick Turnquist, Sales Engineer.
128. Science Research Institute, Petrochemicals, Polymers & Energy Center, California.
129. Solvay, Houston, Texas.
130. Solvay, Brussels, Belgium.
131. The Electrolyser Corporation Inc., Toronto, Ontario, Andrew T.B. Stuart, Vice President Technology.
132. University of Alberta, Department of Chemical Engineering, Dr. K.T. Chuang.
133. Western Sales and Testing, Texas, Steve Aderholt.

Appendix A

Molecular weight H_2	2.016
Liquefaction temperature at 1 atm (NBP ^a)	20.268 °K (-252.732 °C)
Density of liquid at NBP	70.8 kg/m ³
Density of gas at NTP ^b	0.09 kg/m ³
Lower heating value	120 MJ/kg
Higher heating value	144 MJ/kg
Specific heat ratio ($k=C_p/C_v$) at 1 atm , 20°C	1.383

^a NBP: Normal Boiling Point

^b NTP: Normal Temperature and Pressure, 1 bar, 0°C

Table 34: Selected Properties of Hydrogen

Appendix B

Company	End-Use
Abitibi-Price, Thunder Bay, Ont.	Fuel
Armak Chemicals, Saskatoon, Sask.	Fatty amines
Atlas Steels, Tracy, Qué.	Steel
B.C. Hydro, Vancouver, B.C.	Cooling
Central Wire, Perth, Ont.	Wire
Dofasco, Hamilton, Ont.	Steel
Ford Motor, Toronto, Ont.	Plate glass
Great Lakes Wire, Burlington, Ont.	Wire
Greening Donald Co., Hamilton, Ont.	Wire
Hydro-Quebec, Montreal, Qué.	Cooling
Irving Industries, Calgary, Alta.	Wire
Lundy Steel, Mississauga, Ont.	Wire
Maple Leaf Monarch, Toronto, Ont.	Oils & fats
New Brunswick Power Commission	Cooling
Northern Telecom, Ottawa, Ont.	Electronics
Ontario Hydro, Toronto, Ont.	Cooling
PPG Industries, Owen Sound, Ont.	Plate glass
Procter & Gamble, Montreal, Que.	Oils & fats
Quantum Chemical, Toronto, Ont.	Fatty acids
Sidbec-Dosco, Montreal, Qué.	Wire
Stelco, Toronto	Wire
Swift Canadian, Toronto, Ont.	Oils & fats

Source [14]

Table 35: Summary of Major Buyers of Merchant Hydrogen in Canada.

Appendix C

Density at 25°C, g/ml	1.4425
Boiling Point at 1 atm., °C	150.2
Freezing Point at 1 atm., °C	-0.41
Specific Heat at 25°C, kJ/kg	2.628
Heat of Vaporization at 25°C, kJ/g	1.517
Heat of Fusion, kJ/kg	367.52
Heat of Decomposition at 25°C ^b , kJ/mol	≈ 100
Heat of Ionic Dissociation at 25°C ^c , kJ/mol	34.3
Viscosity at 20°C, mPas-s (=cP)	1.245
Surface Tension at 20°C, mN/m (=dyn/cm)	80.4
Specific Conductance at 25°C, per Ω·cm	4 × 10 ⁻⁷

^a Ref. [65,71]

^b $\text{H}_2\text{O}_2 \rightarrow \text{H}_2\text{O} + \frac{1}{2} \text{O}_2$

^c $\text{H}_2\text{O}_2 (\text{aq}) \rightarrow \text{H}^+ + \text{O}_2\text{H}^-$

Table 36: Properties of Hydrogen Peroxide (100% basis)

Concentration wt% H_2O_2	Density at 25°C g/ml	Boiling point at 1 atm °C	Freezing point °C	Vapour composition wt% H_2O_2	Heat of vaporization at 25°C kJ/g
pure water	0.9971	100.0	0.0	0.0	2.442
10	1.0324	101.7	-6.4	0.9	2.357
20	1.0694	103.6	-14.6	2.1	2.274
30	1.1081	106.2	-25.7	4.2	2.192
40	1.1487	109.6	-41.4	7.6	2.105
50	1.1914	113.8	-52.2	13.0	2.017
60	1.2364	119.0	-55.5	20.8	1.926
70	1.2839	125.5	-40.3	33.4	1.832
80	1.3339	132.9	-24.8	51.5	1.733
90	1.3867	141.3	-11.5	75.0	1.627
100	1.4425	150.2	-0.41	100	1.517

^a Ref. [65,71]

Table 37: Physical Properties of Aqueous Hydrogen Peroxide

Appendix D

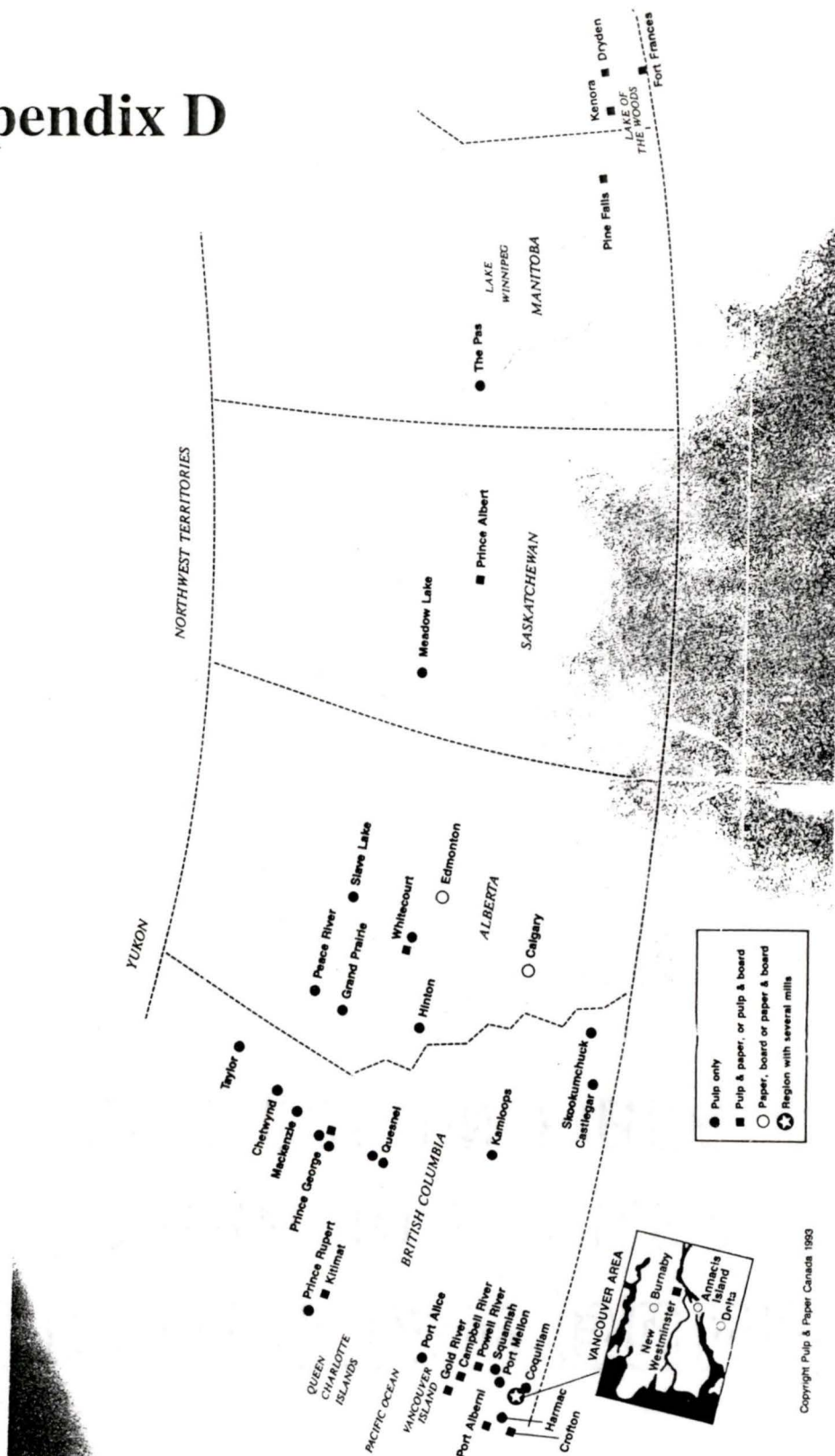
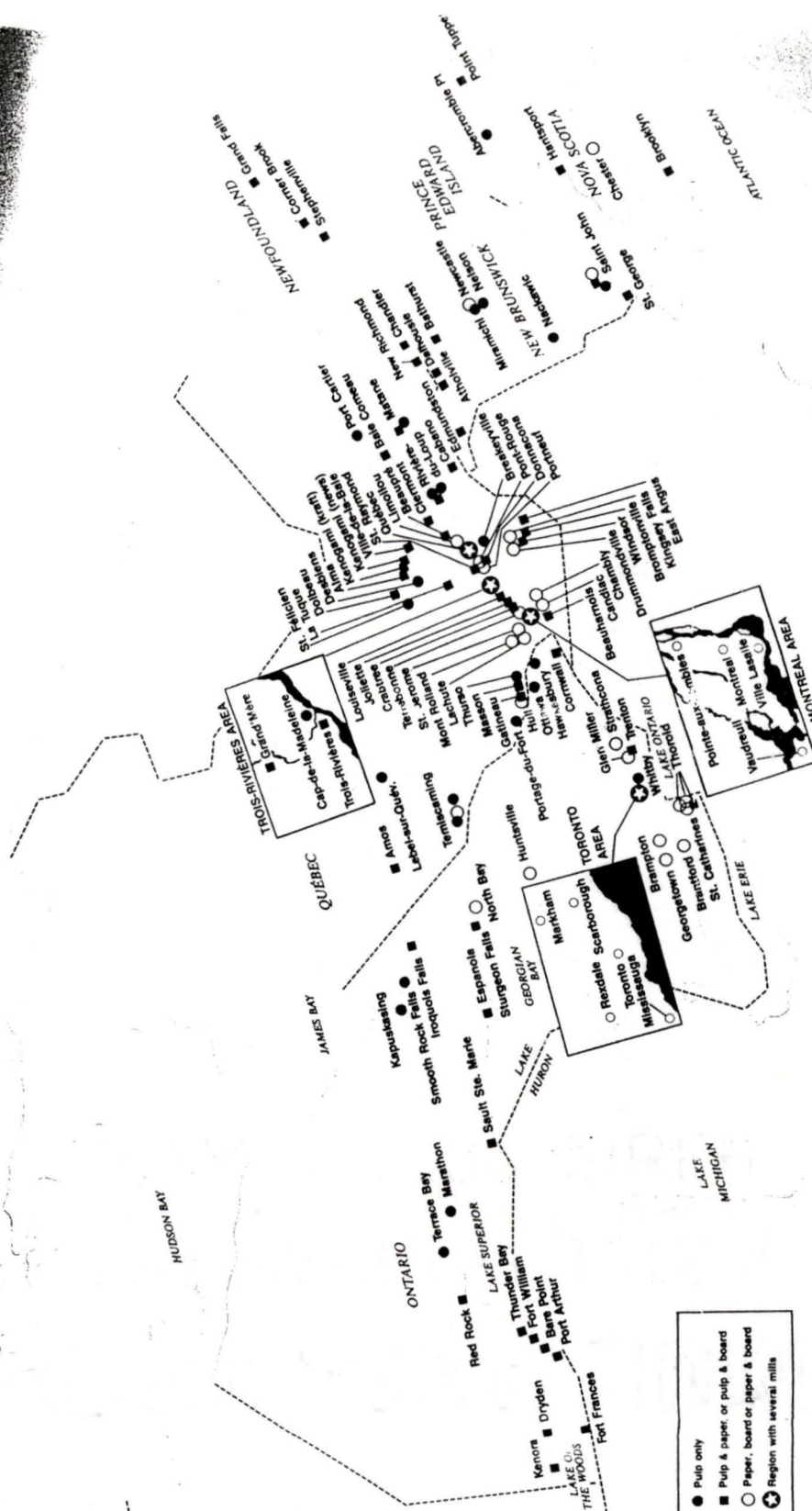


Figure 37: Pulp and Paper Mills in Canada

Source: Pulp & Paper Canada, 1993 [69].



Appendix E

Properties	Methanol	Unleaded Gasoline	Diesel
Constituents	CH ₃ OH	C _n H _{1.87n}	C _n H _{1.8n}
Density, 16°C, 1 atm., kg/l	0.795	0.721-0.785	0.833-0.881
Lower Heating Value, MJ/kg ^a	20.0	43.9	42.5
MJ/l ^b	15.8	33.0	36.4
Heat of Vaporization, 25°C, 1 atm., MJ/kg	1.103	0.305	0.270
Octane Rating, research	106	92-98	
motor	92	80-90	
Autoignition Temperature, °C	464	260-460	257

^a To convert MJ/kg to Btu/lb, multiply by 430.3.

^b To convert MJ/l to Btu/gallon (Imp.), multiply by 4310.

Ref. [84]

Table 38: Properties of Fuels

VITA

Surname: Ouellette Given Names: Nancy

Place of Birth: Warwick, Québec Date of Birth: 67/01/03

Educational Institutions Attended:

University of Victoria	1991 to 1993
University of Sherbrooke	1986 to 1990

Degrees Awarded:

M.A.Sc.	University of Victoria	1993
B.A.Sc.	University of Sherbrooke	1990

Honours and Awards:

Fonds pour la formation de chercheurs et l'aide à la recherche, Postgraduate Scholarship	1992 to 1993
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IESVic

Institute for Integrated Energy Systems

UNIVERSITY OF VICTORIA

P.O. BOX 3055, VICTORIA, B.C., CANADA V8W 3P6

TELEPHONE (604) 721-8931, FAX (604) 721-8936

1993 December 16

Mr. Chris Petter
University Archivist & Head of Special Collections
University of Victoria Archives
McPherson Library
P.O. Box 1800
Victoria, BC
V8W 3H5

Dear Mr. Petter:

I hereby agree that Appendix D (Map of Pulp & Paper Mills in Canada, pp. 130-131) of Ms. Nancy Ouellette's Thesis (M.A. Sc., Mechanical Engineering) "Hydrogen from Remote Excess Hydroelectricity" be withheld from microfilming if it is infringing on the Canadian copyright law.

Yours sincerely,

David Sanborn Scott
Supervisor
Thesis Committee

:dpb

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Author



(Signature)

NANCY OUELLETTE

(Name in Block Letters)

December 14, 1993

(Date)