2003 GENERAL RATE APPLICATION

An application to the
Board of Commissioners of Public Utilities

Proposed Power Rates
To be charged by
Newfoundland & Labrador
Hydro
To
Newfoundland Power,
Island Industrial Customers
and
Rural Customers

May 2003

Volume III

Newfoundland and Labrador Hydro
2003 General Rate Application

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Fuel Oil Practices Review and Policy

Newfoundland and Labrador Hydro
December 10, 2002

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Introduction

Newfoundland and Labrador Hydro's ("Hydro") practices regarding the purchase, storage and pricing mechanism for heavy fuel oil at the Holyrood Generating Station were reviewed during its 2001 General Rate proceeding. Subsequently, the Board of Commissioners of Public Utilities ("the Board") in its Decision and Order No. P. U. 7 (2002-2003), directed Hydro "***to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing, along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity,***" (Order No. P. U. 7 (2002-2003) Pages 56, 166 and paragraph 5 (ii), p. 176).

This report, filed in response to this direction, includes:

- A. A review of a possible oil hedging program;
- B. An overview of Hydro's heavy fuel oil inventory and purchasing practices;
- C. A review of Hydro's heavy fuel oil storage capacity;
- D. Hydro's policy and procedure regarding the purchase of fuel for energy production.

Oil Hedging

Hydro retained the services of Risk Advisory, an independent risk management group, to review fuel oil hedging. The review undertaken by Risk Advisory was comprehensive and covered several aspects of an oil-hedging program, including the usual goals of such a program, the types of hedging programs in use, the benefits of oil hedging programs and the implications of the Rate Stabilization Plan (“RSP") on a possible hedging program.

Risk Advisory recommended that, prior to proceeding with an oil-hedging program, Hydro undertake a review of the added stability such a program would have in addition to the RSP. They further recommended that, if this analysis concluded there was a significant advantage, Hydro should then consider a collaborative approach between the regulator and major interveners, including conducting workshops with the regulator and interveners and determining at least some consensus on the risk appetite of the ratepayer.

A review of the passive or automated program as recommended by Risk Advisory was conducted by Hydro’s Oil Hedge Committee and consultation with Risk Advisory was included. The following scenarios were evaluated.

1. Impact of fuel price variation without an RSP and without hedging
2. Impact of fuel price variation with an RSP but without hedging
3. Impact of fuel price variation with an RSP and with hedging
4. Impact of fuel price variation without an RSP but with hedging

The analysis indicated that there is an approximate 50% reduction in the variability of the rate impact, year over year by having an RSP alone. Having a hedge program alone would effect an approximate 25% reduction in the variability of the rate impact. However, these are not cumulative and the impact of having both is approximately 60% or 10% better than the RSP alone. In terms of dollar volatility annually on the ratepayer’s bill, with oil hedging in addition to the RSP, there is an approximate $10 to $15 reduction in variability.

Given the potential significant cost (expected to be in the tens of thousands or higher) in terms of administration, consulting services and regulatory burden associated with the implementation of an oil hedging program, Hydro concluded that the relatively small decrease in the volatility of rates with both RSP and oil hedging, over the RSP alone, is of little additional real value. The RSP alone has the single biggest impact in terms of rate stability and predictability. A passive hedging program is not intended to "beat "the market. It is designed to levelize or minimize the variation on a month-by-month or year-by-year basis and this is also achieved with the RSP.

The additional 10% stability demonstrated in the analysis is not considered substantial enough to warrant the additional administrative and regulatory cost associated with implementing an automated oil hedging program and it is thus recommended that Hydro not undertake a formal oil-hedging program. Hydro's summary of the benefits of an automated hedging program is attached as Appendix I, and the report from Risk Advisory is included as Appendix II.

Heavy Fuel Oil Inventory and Purchasing Practices

Hydro normally tenders for the supply of heavy fuel oil for the Holyrood Generating Station on a three to five year basis. The price has been tied to an index in New York Harbour less a discount. This provides stability and avoids pricing changes on a daily basis in an extremely volatile market. Prior to the current contract, Hydro had in place a volume contract wherein anticipated future needs for three years was covered. With the varying use, which is tied primarily to load growth and energy demand, as well as hydraulic conditions (i.e. the amount of rainfall in reservoir areas), this contract actually covered approximately five years.

In 2002 there was a review of the specification both technically and contractually. A consultant, United Fuels International, was retained to assist in this review. A number of changes were made prior to tender, including changes in the chemical content of the oil to better reflect available supplies and to reduce some aspects of the environmental emissions, and the price setting mechanism was changed to be the average price for the month in which the fuel was ordered for delivery as opposed to the average for the month in which the oil was received. As well, Hydro incorporated into the tender a provision to move to a lower sulphur fuel in case of change in legislation or a more proactive environmental approach. These enhancements were made based on Hydro's experience and the recommendations of United Fuels International.

The current time-based contract is a three-year supply contract with an option for an additional two years, regardless of what the annual or contract period consumption is. Hydro may also buy up to 20% of total supplies on the spot market; however, this has seldom been used. The approval of Hydro's Management Committee is required to purchase on the spot market.

In the preparation of this report Hydro reviewed daily and monthly average prices from 1999 01 01 to 2002-10-31. This review indicates that pricing is very volatile with considerable daily and monthly variation. This is provided in graphical form in Chart 1. Many factors affect the price besides supply and demand, i.e. world events, politics, OPEC activities, etc. and this all contributes to the volatility. By contracting on an average monthly price for the amount on order, Hydro has avoided the daily volatility to some degree.

On examination of Chart 1 and in hindsight, one can suggest times when Hydro could have bought projected needs early or ‘topped up’ the tanks to reduce cost. However, to put this in context, one must consider what action should be taken at any given point. This is based on one’s view at the time of future pricing. Is it going to continue to go down or will it go up? That is the dilemma that Hydro faces in deciding if it should gamble with the ratepayers’ money and stockpile large amounts of No. 6 fuel when the price is low. Unfortunately, conditions may very quickly turn around and the price could drop even lower. It’s a gamble and Risk Advisory stated in its report Hydro should not expect to outperform the market as it does not have the ability to do so on a consistent basis.

Hydro’s oil use varies due to hydraulic availability as well as the load variability, which besides new customers is driven by the erratic Newfoundland weather. All in all, the predictability of oil usage is not reliable on a short-term basis and it does not permit speculation in the oil market to attain sustained gains. In fact, there is the possibility of significant losses. In the period reviewed from 1999 to 2002 there were approximately thirty (30) purchases of fuel oil with most activity in the high load season, i.e. October to April. This is indicated in Chart 2 (attached). The low periods are generally mid-summer when, depending on the hydraulic situation, all units at Holyrood may be shut down for varying periods of time.

There is also an increased risk of spill either from the storage facilities or during tanker offloading activity if there is more inventory carried than needed. This, of course, would involve significant clean up cost.

There is no methodical way that Hydro can consistently envisage where the price of oil is going over time and there will always be a down side risk, which must be weighed carefully prior to speculation.

With this in mind, Hydro has concluded that its practices are adequate and in the best overall interest of ratepayers. Hydro plans for the minimum inventory levels, which, with monthly average pricing, an RSP and lesser environmental risk are in the best interests of ratepayers.

Increase in Storage Capacity

In light of the comments in the previous section, on the present fuel purchasing and inventory practices, there is no justification for increasing the storage capacity at Holyrood. The current storage levels are adequate for Hydro's operational needs. If there were merit in buying on a speculative basis, the first consideration would be to use the current inventory capacity and gauge success before proposing a new fuel tank at Holyrood. However, an estimate of the cost of a fifth tank at Holyrood was prepared and is in the order of $10 million with an accuracy of plus or minus 20%. Based on this estimate and the foregoing discussion, there is no justification to formalize the estimate to a more accurate figure. As well, Hydro briefly explored the possibility of a five (5) km pipeline to the Ultramar Storage facility at Holyrood. Cost estimates were not undertaken as Hydro was informed that the tanks are not available for No. 6 oil storage.

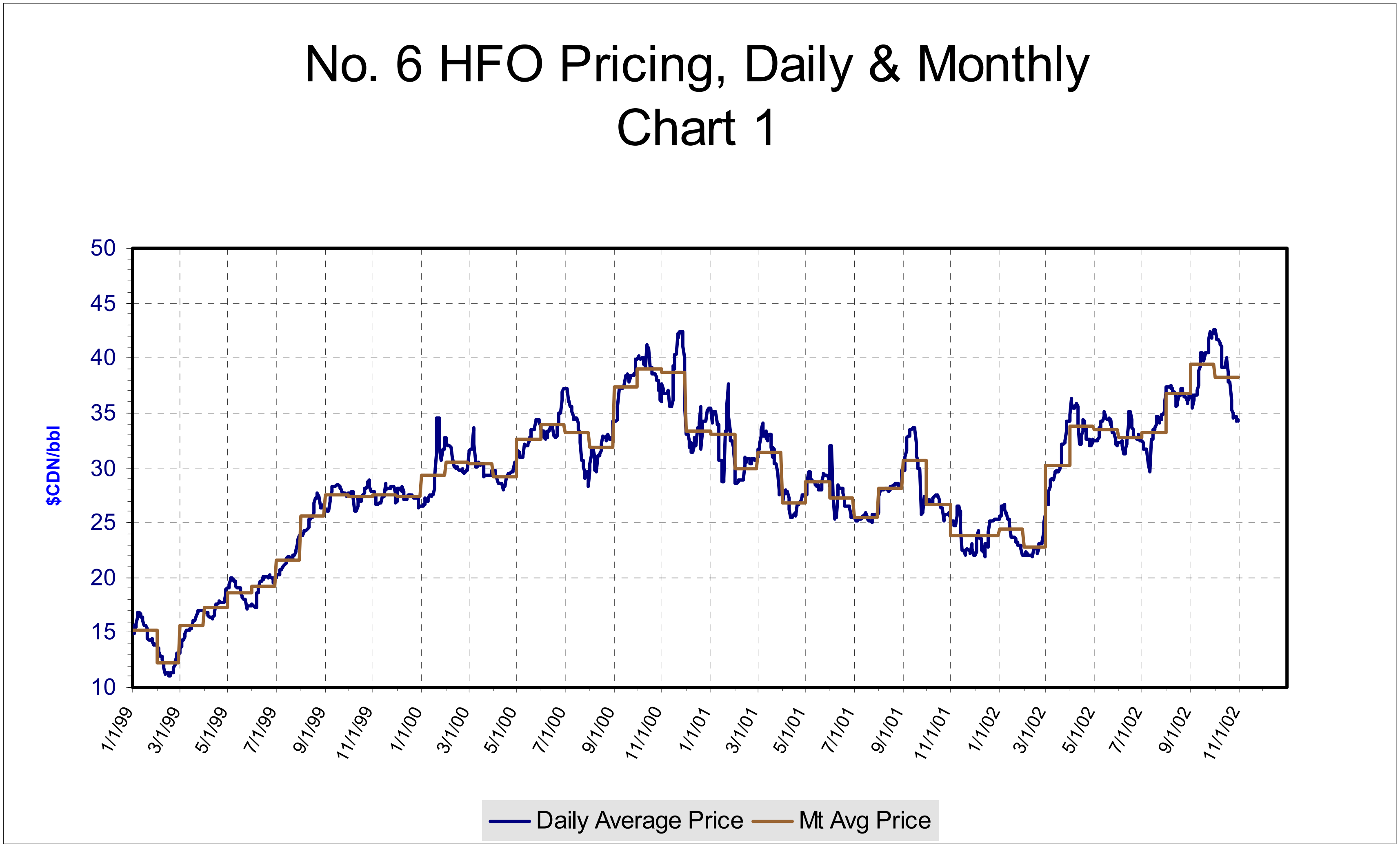
If there were merit in this type of speculation, a more appropriate course of action would be to pursue a hedging mechanism.

Policy and Procedure for Oil Purchases

A policy regarding the purchase of heavy fuel oil, as well as light oil used in gas turbines and diesel plants is attached as Appendix III. This policy and procedure outlines the responsibility for those involved in the fuel specification, procurement and storage of fuel oil. Overall, executive management responsibility for all production-related fuel management has been assigned to the Vice-President, Production.

Summary

This report demonstrates that Hydro’s current practices are prudent and result in the lowest reasonable costs for heavy fuel oil. No change is recommended with respect to a hedging program for these purchases or increased storage capacity or in purchasing practices.



No. 6 HFO Pricing, Daily & Monthly
Chart 1
$CDN/bbl
50
45
40
35
30
25
20
15
10
1/1/99
3/1/99
5/1/99
7/1/99
9/1/99
11/1/99
1/1/00
3/1/00
5/1/00
7/1/00
9/1/00
11/1/00
1/1/01
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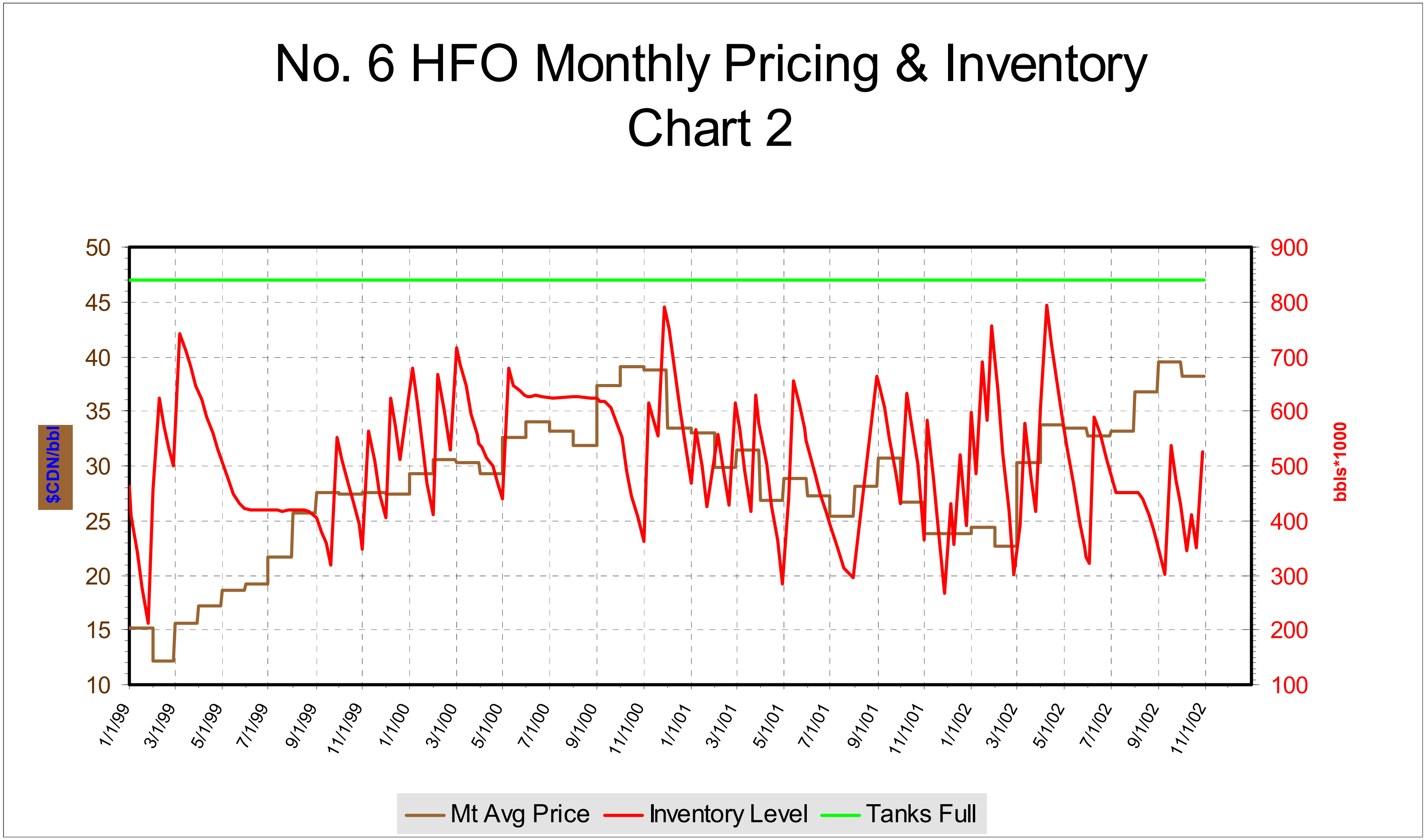
Daily Average Price
Mt Avg Price



No. 6 HFO Monthly Pricing & Inventory
Chart 2
$CDN/bbl
bbls*1000
50
45
40
35
30
25
20
15
10
900
800
700
600
500
400
300
200
100
1/1/99
3/1/99
5/1/99
7/1/99
9/1/99
11/1/99
1/1/00
3/1/00
5/1/00
7/1/00
9/1/00
11/1/00
1/1/01
3/1/01
5/1/01
7/1/01
9/1/01
11/1/01
1/1/02
3/1/02
5/1/02
7/1/02
9/1/02
11/1/02
Mt Avg Price
Inventory Level
Tanks Full

APPENDIX I

BENEFITS OF AUTOMATED HEDGING PROGRAM

Report from
Oil Hedging Committee

Newfoundland and Labrador Hydro

December 18, 2002

Introduction

In 1998 Hydro formed an internal committee, referred to as the Oil Hedge Committee or OHC, to analyse and review on an ongoing basis the feasibility of hedging its fuel oil requirements using various financial instruments. This is in contrast to Hydro's historical practice of buying on a spot basis. The OHC prepared various reports and policies under an assumption that oil hedging would likely be an appropriate risk management activity for the company and its customers. The OHC also tracked various 'phantom hedges', in an effort to more directly understand the mechanics, decision-making, and outcomes of various hedge activities. During the 2001/02 rate hearing, Hydro provided an overview of its hedge activities to date. In its Order (P.U. 7 2002-2003) dated June 7, 2002 the PUB ordered:

> "The Board will require NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity."

This memo, and its attachments are directed towards the "oil hedging program" component only. The purpose of this memo is to convey the conclusions of the OHC regarding the implementation of an oil hedge program at Hydro.

The Goal of a Hedging Program

To ensure that the OHC adequately addressed the PUB's interest in oil hedging, the OHC retained the professional services of an independent risk management company, Risk Advisory, to prepare a report providing an overview of hedging, and an examination of the merits of such risk management activity for Hydro. This report has been completed and is attached in Appendix II.

A key finding of the attached report, is that the goal of a successful oil-hedging program, should not be lower oil costs. Instead, hedging is more about bringing certainty and stability to an uncertain production cost variable: in this case, fuel oil costs. In the short or medium term, hedged fuel oil costs may in fact be lower or higher than prevailing spot market prices. Over the longer run though, the average commodity price incurred under either management option (hedged or unhedged), is expected to be the same (with the exception that hedging has an added modest transaction and administrative cost).

Type of Hedge

If Hydro were to adopt a hedging program, RiskAdvisory recommends an automated approach to hedging, where oil requirements are hedged in pre-determined quantities and time horizons, using pre-determined risk management instruments. This approach is recommended over a more subjective approach, that entails the adoption of a market view in its application. RiskAdvisory maintains, that Hydro should not be expected to possess a level of expertise that suggests that it can outperform the markets.

The Benefits of a Hedging Program

The advisability of a hedging program for Hydro then, comes down to a question of whether the reduction in rate volatility as a result of the introduction of the Program, is of a sufficient magnitude, to warrant the added cost to the ratepayer.

Hedging can reduce oil price volatility, which is the variation that prices can be subject to, over a given period of time. In a circumstance where a rate Stabilization Plan (RSP) does not exist, significant movements in oil prices over the course of a year, can translate into significant rate shocks. Hydro's wholesale and industrial rates could as a result, be quite unstable and uncertain, and in effect, more volatile. An important insight from Risk Advisory is that, for technical reasons, forward market prices have lower volatility than spot markets. Thus, hedging utilizing forward prices, can reduce price uncertainty relative to a reliance on the more variable spot markets. Analysis indicates that in terms of relative volatility, fifteen month forward prices are 45% less volatile than spot prices. If a reduction in rate volatility and uncertainty is a desired outcome for Hydro, then a longer-term oil-hedging program makes strategic sense. However, such a conclusion needs to be tempered due to the presence of the RSP.

RSP and Hedging Impacts on Volatility

The RSP has the important effect of reducing volatility in rates by smoothing out variations in Hydro's embedded oil price over multiple years. Thus the RSP already supports an important strategic outcome of an oil hedge program. Our analysis indicates that the RSP, in its current form, reduces potential price volatility by about 50 percent relative to rate change exposure in any given year with no RSP. The important question then becomes, what is the additional reduction in rate exposure afforded to consumers when an oil hedge program is overlaid on top of the RSP?

Our simulations indicate that a further reduction in potential rate exposure of about 10% is realized assuming that one-half of its fuel oil requirements were automatically hedged [1]. Thus administering an oil hedge program on top of the RSP renders a rather marginal gain in rate volatility protection for the consumer.

Impact on the Customer Bill

To assist in decision-making, Treasury, in consultation with Economic Analysis and Rates, performed a statistical analysis of possible customer cost exposures due to oil price changes. Impacts on electric heat customers in terms of their annual electricity costs were tracked, based on assumed changes in oil prices. To provide a proper perspective, results were plotted over a five-year period under the following scenarios.

No RSP and No Hedging – NRNH
With RSP but No Hedging – WRNH
With RSP and With Automated Hedging of 50% of Oil Requirement – WRWH
No RSP but With Automated Hedging of 50% of Oil Requirement- NRWH

1 While the Committee has not made a decision as to the appropriate level of hedging, 50% was considered a reasonable level to choose along a spectrum of possibilities between 0% and 100%, particularly when considering the uncertainty associated with timing of receipt of oil shipments.

A Monte Carlo simulation (5000 trials) was performed, that plotted the various rate outcomes that could result from a series of possible oil price changes (all other factors being kept constant). The table below illustrates with 95% statistical certainty, the highest possible annual bill impact for any given year, for the average all-electric customer.

Table 1

SUMMARY OF PROBABILITY RUNS
IMPACT OF CHANGES IN OIL PRICE
Limits Within the 95% Percentile

	YR1	YR2	YR3	YR4	YR5
Annl Bill Impact Elec Ht - NRNH	134.15	124.48	124.21	129.37	123.99
Annl Bill Impact Elec Ht - WRNH	0.00	67.07	65.70	62.51	63.07
Annl Bill Impact Elec Ht - WRWH	0.00	55.06	55.12	47.83	46.00
Annl Bill Impact Elec Ht - NRWH	110.13	94.13	92.03	94.78	95.59

It is important to note that each of the results presented in this table are independent, and represent only one of the 5000 trials performed. So for example, the Year 1 and 2 results of $134.15 and $124.48 respectively, represent the results of two totally separate cases that were run, and are not interrelated. Statistically, it is virtually impossible for there to have been a $134 increase in Year 1, followed by another $124 increase in Year 2. In fact, in analysing the data associated with the Year 2 run, the Year 1 value was actually only $2 for that particular run.

These results confirm our expectations as they relate to relative effectiveness of the RSP versus a hedging program. The presence of the RSP basically reduces exposure by one half [2], which is to be expected since price increases are deferred over the following two years. The addition of a hedging program in which 50% of oil purchased were hedged, results in a further lessening of annual exposure, but not to the same extent as the RSP. In year 2 for example, while the RSP reduces total exposure by $57 (124.48 – 67.07), or 46%, the overlay of a hedging program results in a further reduction in exposure of only $12 (67.07 – 55.06), or only 10% of the original $124

2 The 100% volatility reduction in Year 1 is a reflection of the current policy of deferring impacts on rates of oil price variations in a given year, to the *subsequent* two years.

of exposure. This appears to be a minimal gain for the additional administrative and regulatory burden that would be associated with such a program.

Conclusions

While the introduction of an oil-hedging program can serve to reduce rate volatility, its incremental impact is severely muted by the presence of the Rate Stabilization Plan. In addition, the introduction of a hedging program is not without its own costs, including transaction costs associated with the various hedge positions and administrative costs. Risk Advisory suggests a transaction cost per barrel hedged of $0.20 US per barrel. Assuming an exchange rate of 1.6 CAD per USD, and an annual commitment of 3 million barrels, one-half of which are hedged, this would amount to additional transaction costs of approximately $480,000 p.a. Cdn. (not including added internal administrative costs). In addition to transaction and administrative costs, there can be significant opportunity costs associated with being locked into a higher price. While these costs theoretically can be recovered through a long term, consistent application of the Program, Hydro's fuel oil costs can be significantly increased in the intervening periods due to short term opportunity costs associated with out of the money hedge positions. This can increase the regulatory uncertainty associated with a hedge program during those intervening periods.

Assuming the continued operation of the RSP in its current form, the added costs and regulatory uncertainty of an oil hedge program do not appear warranted, given the limited potential for reduced rate volatility for the customer.

APPENDIX II

REPORT FROM RISK ADVISORY

Newfoundland and Labrador Hydro

EXAMINATION OF THE MERITS OF A #6 OIL RISK MANAGEMENT PROGRAM

September 11, 2002

Prepared by Tim J. Simard and D. Leigh Parkinson
Principals, RiskAdvisory

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SCOPE OF REPORT

RiskAdvisory has been retained by Newfoundland and Labrador Hydro ("Hydro" or "the Company") to prepare a report containing an overview of the issues associated with the hedging of purchases of #6 HFO 2.2%. The report addresses the hedge program in the context of Hydro's Rate Stabilization Plan ("RSP"), and examines the potential for such a hedge program to further the Regulator's stated objectives of rate stability and predictability. The report also discusses the advisability of a hedge program for Hydro and reviews the distinction between a subjective and automated hedging approach. RiskAdvisory provides a recommendation with respect to the preferred approach and details an implementation strategy for Hydro.

The report is based on RiskAdvisory's extensive experience with corporate risk management programs and electric utility programs in particular, combined with experiences in the utility regulatory arena surrounding risk management programs. RiskAdvisory has also held discussions with Hydro senior management to develop a better understanding of the factors that will influence the selection of a prudent risk management framework.

BASICS OF HEDGING

Financial markets have evolved so that participants in the energy industry are able to enter into transactions that alter the nature of their commodity market price exposures. While there is a broad range of hedging instruments available to manage the cost of energy purchases, three of the most common tools employed are swaps, caps and collars.

FIXED-FOR-FLOATING SWAPS

A swap is a financial transaction entered into between two counterparties where cash flows are "swapped". In a fixed-for-floating swap transaction, one party pays a fixed price to its counterpart, who in turn makes a "floating" or "index" payment to the first party. For example, Hydro can enter into a financial transaction with a counter party whereby it receives a monthly floating cash flow tied to the Platt's index price for New York Harbor #6 Heavy Fuel Oil ("HFO") 2.2% and pays a fixed price of USD 20.00 per bbl[1]. The swap confirmation executed by the counter parties will define the volume underlying the transaction (e.g. 120,000 bbls per month), the floating index to be used, the fixed price, and the term of the contract (e.g. January 2003 through March 2003). Once the index price has been established, a difference cheque flows between the two counterparties representing the difference between the index price and the fixed price on the volume specified in the swap confirmation. For example, in the example outlined above, if the January 2003 Platt's index price for #6 HFO 2.2% is set at $18.00, Hydro would be required to make a $240,000.00 payment to its counter party ($20.00 fixed price less the $18.00 index price multiplied by 120,000 bbls).

The purpose of the fixed-for-floating swap is to convert a volatile index exposure to a stable fixed price exposure. Hydro would continue to pay an index-based price to its

[1] **Unless otherwise noted all currency references are US Dollars**

physical market supplier. In a well-designed hedge, the floating index component that is paid by Hydro to the supplier is paid to Hydro under the floating leg of the swap. In turn, Hydro makes the fixed price payment to the financial counterparty. From Hydro's perspective, the floating index inflow and outflow cancel out, leaving the Company with a net fixed price obligation for the volume of fuel oil underlying the hedge transaction. Hydro and its ratepayers would forego the opportunity to participate in a falling HFO market environment in return for complete protection against a price escalation.

The fixed price established in the contract is based on competitive prices established in the over-the-counter forward market. Market participants include financial houses, physical traders, fuel oil producers and fuel oil consumers. There are several counterparties that Hydro can solicit to enter into these types of transactions. These counterparties will be aware of the fixed price at which fuel oil can be purchased and sold in the forward market. The most aggressive counterparty will quote the lowest price to Hydro. A further discussion on the liquidity characteristics of the #6 HFO 2.2% forward market appears later in this report.

In an efficient market, over the long-run entering into a consistent program of fixed-for-floating swaps will lead to a net gain or loss on these transactions of zero. The forward price represents the market's consensus expectation of future spot prices. In practice, implicit transaction costs will create some slippage and over the long-run lead to a net cost associated with a fixed-for-floating swap program. As an example, if the average bid-offer spread for #6 HFO 2.2% was $0.10 per bbl, one would expect a long-run cost of $0.05 per bbl representing one half of the bid-offer spread. If the bid-offer spread for more distant months, quarters or annual strips widens to $0.25 per bbl, the long-run cost of hedging would escalate to $0.125. Note that with swaps, one does not have to pay a brokerage fee. However, the financial counterparties earn their fee as principals in these transactions through the bid-offer spread.

DETERMINATION OF FORWARD PRICES

In some commodity markets like the gold market for example, the forward prices established in the marketplace between buyers and sellers are tied very closely to the spot price of gold. The forward price of gold in one month will equate to the spot cost of gold in addition to the carrying costs associated with holding the gold for one month. As a result, forward prices for gold are always higher than the spot price, and there is a very strong correlation between movements in the spot price and movements in the forward price. Gold traders engage in riskless arbitrage opportunities between the spot and forward prices to ensure that this relationship exists.

This relationship does not behave in a similar fashion in the energy markets. The main difference between a commodity like gold and energy commodities is that there is a significant need to consume the commodity immediately and that in tight supply situations, one is unable to borrow the energy. Imagine a cold winter where spot heating oil prices are trading at $1.00 per gallon and prices in one month are trading at $0.80. This type of situation could not arise in the gold market – one would immediately sell the gold today, invest the proceeds, and enter a forward contract to buy the gold back in one month and collect a riskless arbitrage profit. However, in the heating oil market, the spot price is high today because people need to consume the energy – they have the option of selling it today and buying it back at a lower price in a month's time, but in the meantime they will be very cold. Also, as an arbitrageur, to take advantage of this situation, one would borrow heating oil today, sell it for $1.00 per gallon, enter a forward position to buy it back in one month's time at $0.80, and then return the heating oil to the lending party, collecting an $0.20 arbitrage profit less the cost of borrowing. The problem here is that in a tight supply position, one will not be able to find anyone who is willing to lend the heating oil for the month. As a result, in the energy markets there will often be times when the spot price is well above the forward prices, and the reverse can happen as well. In general, the correlation between spot prices and forward prices in the energy markets is not nearly as strong as in other commodity markets – spot prices can move up or down without much impact on forward prices. Historical evidence suggests that oil market participants have an expectation towards mean reversion (prices returning to their historical mean) and this is what often drives the shape of the forward curve. While this relationship could change at any time, it is typical that when WTI crude is well above $20 per bbl, the market trades in a backwardated fashion (forward prices below spot prices) with the market expectation that over the long-run prices will return closer to the $20 level. Conversely, when spot prices are well below $20, the forward market tends to trade in contango (forward prices above spot prices), once again with the expectation that prices will return closer to the $20 level.

CAPS

Hydro can obtain insurance for its ratepayers against higher HFO costs through the purchase of call options or "caps" on the #6 HFO 2.2% price. The insurance is structured so that in return for an upfront premium, a financial counter party will compensate Hydro for any rise in the HFO index price above a pre-set price known as the "strike price". For example, with forward HFO prices at $20 for the first quarter of 2003, Hydro may be able to acquire $22 monthly caps for a premium of $1.00 per bbl. If the HFO index price is established below $22 in any of these three months, the insurance policy expires worthless – the premium is still paid but there is no payout. However, if the index price in any month settles above the $22 strike price, Hydro is compensated for the full difference between the index price and the strike price. On 140,000 bbls per month, if the index settles at $25 in January, Hydro would receive a cap payout of $420,000 ($25 less $22 multiplied by the 140,000 bbls).

The attraction of the cap vis-à-vis the swap transaction is that Hydro and its ratepayers retain significant participation in the case of a fall in HFO prices. If the HFO price falls to $15, the only opportunity cost to the ratepayer is the premium of $1. The net cost including the cost of insurance is $16. Note that under the fixed-for-floating swap, if the HFO index is set at $15, the net price for Hydro's ratepayers remains fixed at $20. However, the cap structure does not provide as much insulation against the price rise. In the $25 scenario outlined above, the net cost of HFO to the ratepayer is $23 (the $22 cap price in addition to the $1 cap premium), whereas under the swap transaction the net cost would be $20.

The over-the-counter financial markets allow Hydro to select its choice of cap. The premium for the cap declines as the strike price is increased. This is analogous to the decline would one expect to see in conventional insurance policies as the deductible is increased. If one purchases a $22 cap when the forward price is $20, one must absorb the first $2 rise in price before the insurance protection commences. If one acquires a

$25 cap, one must absorb the first $5 increase in price before receiving the protection of the insurance. The premium charged for the call option is established in a competitive pricing environment and is based on a number of factors including the market's perception of potential price volatility over the term of the cap.

As with swaps, over the long-run in an efficient market the payout on the caps will equate to the premium paid for the caps, less any implicit transaction costs. The premium one pays for these caps will equate to the market's consensus view of the expected payout from these caps, once again net of transaction costs.

COLLARS

The collar transaction would allow Hydro to create a band around the HFO index price for its ratepayers. It contains a cap as outlined above. However, instead of paying the full premium for the cap, part or all of the premium can be defrayed by providing the counterparty with a floor. For example, instead of acquiring a $22 call for a premium of $1, Hydro could acquire the call and simultaneously sell a $19.50 floor (or "put option") to its counterparty. From the counterparty's perspective, it estimates that the value of the $19.50 floor equates to the value of the foregone premium.

In this example, no payment would flow between Hydro and the counterparty if the index settles anywhere between $19.50 and $22.00. If the index settles above $22.00, Hydro and its ratepayers are protected, ensuring a maximum price of $22.00. If the index settles below $19.50, Hydro must pay to the counterparty the difference between the index price and the floor strike price. This establishes a minimum price for the ratepayer of $19.50.

The transaction above is an example of a zero-premium collar – no upfront premium is required. The transaction can also be structured so that a lower floor is established with a reduced premium versus the outright purchase of the call. For example, one might acquire a $22 cap and sell a $17 floor for a net premium payment of $0.50.

The hedge protection provided by the collar lies somewhere between the cap and the fixed-for-floating swap structure. The collar does not provide as much protection as the swap, but allows for partial participation in a falling HFO price environment. The collar can provide more price protection than the cap structure due to the lower premium outlay, but does not permit the same degree of participation in a price decline.

The expected hedge profit from collar transactions once again over the long run will be zero, net of any implicit transaction costs.

THE #6 HFO FORWARD MARKET

This section will discuss the types of #6 HFO that are traded in the forward market, the liquidity constraints for HFO with varying sulfur content focusing on the term of transactions, anticipated bid-offer spreads and the number of counterparties one should expect will be willing to quote prices. There will also be a discussion of volatility characteristics in the HFO market along with a review of the relative price volatility of USD-denominated HFO prices and CAD-denominated fuel oil prices.

RiskAdvisory contacted several counterparties known to be active in the fuel oil markets to solicit their expert opinion on the general characteristics of the various HFO types (1%, 2.2% & 3%) with regard to the liquidity, breadth and the term structure of these markets. We will discuss HFO 1% & 3% collectively and then deal with 2.2% specifically. HFO 1% & 3% are both characterized as extremely liquid markets with numerous active physical buyers and sellers, financial intermediary participants, speculators and are both actively covered by the broker community because of the active two-way flow. However, the two grades have geographical and seasonal influences. Most of the 3% HFO traded is in the Gulf Coast and therefore would not be a viable fuel hedging alternative for Hydro's consideration. 1% New York Harbor trades actively in winter but is less liquid in summer. The ratio of transactions of 1% New York Harbor to 3% HFO is better than 2:1. Bid/offer spreads in these liquid seasons and grades for the spot month contracts can be as narrow as USD0.05-0.10 expanding to USD0.25 for a one-year strip. As with all energy commodities liquidity declines as term is extended but both grades are still considered to be sufficiently liquid out at least three years and would serve as viable hedge instruments. The West Texas Intermediate crude oil volatility curve escalated by approximately 3 percent serves as a reasonable proxy for HFO volatility. This currently equates to 39% for spot volatility declining to 30% 15 months out. 30% volatility would imply a potential variance in a $20.00 forward price between $14.00 and $26.00.

HFO 2.2% has quite different characteristics from the other two grades and is isolated to New York Harbor. It is significantly less liquid than the other two grades at their seasonal peaks and geographic locations and less liquid than New York Harbor 1% during the winter months. There are fewer physical market participants compared to the other grades and deal activity levels average about six transactions a week. Even at this relatively low level of activity most counter parties will provide a bid or offer on request. Bid/offer spreads are USD 0.15-0.25 wide for the near month expanding to $0.35-0.40 for a one-year strip.

There are approximately six counterparties who consistently make markets in HFO but only a couple who run significant books. Brokers are active in these markets but the majority of larger transactions take place between these half a dozen counterparties and the customer. For all three grades individual near month contracts trade actively but beyond the first few months, activity is focused in quarterly, calendar year or longer-term strips. For example, at this time of the year counter parties will quote most actively on the balance of 2002, 1st quarter 2003, calendar 2003 and subsequent calendar strips. As we move into the 4th quarter of this year 2nd quarter 2003 gets added to the mix. Counterparties will quote individual outer months (e.g. December 2003), or quarters (e.g. 4th quarter 2003) on request but pricing could reflect a lesser transactional appetite compared to the conventional strips. Correlations between the different grades are not perfect but 1% HFO would be closest to 2.2% HFO. Any counter party that Hydro has a relationship with now or develops in the future will have done some correlation analysis and should be willing to share this information. The options market for all grades of HFO is fairly illiquid. This would indicate that certain structures would not always be available and if a counter party was prepared to provide a quote, the lack of liquidity would translate into higher premiums and could add significant costs to an option-based hedging strategy.

The fuel index used in Hydro's fuel acquisition is NY Harbor 2.2%. The discussion above indicates that there are more liquid grades in the forward HFO market than this particular grade. As a result, one might consider using an alternative index like NY Harbor 1% to capitalize on the higher liquidity characteristics. The problem with this approach is that it exposes Hydro to unwanted basis risk. Basis risk describes the phenomenon where there is an exposure to the fact that the price movement in the underlying exposure may not behave in the same fashion as the price movement in the index used to hedge the exposure. If one enters into a 1% forward position to hedge a 2.2% price exposure, one runs the very real risk that the 1% price could move lower (generating hedge losses) at the same time the 2.2% price moves higher generating higher acquisition costs. RiskAdvisory recommends that Hydro avoid the exposure to this basis risk by absorbing the moderately higher transaction costs associated with the 2.2% market.

It is a common characteristic of energy commodity markets to see a decline in anticipated price volatility as one extends term. The perception in the market is that there are many events which can cause sudden and dramatic price movements to the spot price (wars, natural disasters, short-term supply anomalies, weather) that will have only a limited impact on the market's expectation for prices in more distant timeframes. Hurricanes in the Gulf of Mexico may cause short-term disruptions in oil supplies which serves to fuel a rise in spot prices, with market participants recognizing that the impact is not likely to extend beyond the current month, leaving forward prices one year out potentially unchanged. Similarly, a warm winter along the US East Coast may depress spot HFO prices, but the expectation of a more normal weather environment next year will limit the impact again on one-year forward prices. One may recall the Persian Gulf Crisis when spot WTI prices soared from $17 to over $40 per bbl in a matter of days, with one-year forward prices moving less dramatically from $20 to $27.50 per bbl. Prices in more forward months showed even less reaction to the Gulf War.

In an environment where no hedging is used by Hydro to insulate ratepayers over and above the protection provided by the RSP, the cost of HFO is determined by monthly HFO index prices, which will be subjected to the monthly spot volatility of HFO. If Hydro moved to an acquisition strategy where it purchased its HFO on a forward basis out one year, then the change from one month to the next would be a function of the monthly volatility in the one-year forward month. There will typically be a material reduction in these relative volatility levels. As an example, the quoted market volatility (available from options traders) for a one-month forward WTI position is approximately 35%. However, the volatility for a twelve-month forward position for the next month is only 15%, less than half the quoted volatility for the one-month contract.

Another element to examine is the difference between USD-denominated HFO volatility and CAD-denominated HFO volatility. If Hydro does not hedge either the USD HFO commodity price or the CAD/USD exchange rate, the ratepayer is exposed to movements in the combined CAD HFO price (the USD HFO price multiplied by the CAD/USD exchange rate). If Hydro hedges its anticipated USD obligation through a currency hedge but leaves the USD HFO price unhedged, the ratepayer is exposed to the USD HFO price volatility in isolation. If we assume mid-range volatilities of 30% for HFO and 6% for the CAD/USD exchange rate along with an assumption of zero correlation between the exchange rate and the HFO price, an interesting result emerges. While the USD HFO price volatility is 30%, the CAD-denominated HFO price volatility is only marginally higher at 30.6%. The 30.6% volatility is derived by calculating the standard deviation of the portfolio (the portfolio in this case is HFO and the CAD) and the correlation of the elements within the portfolio which in this case is assumed to be 0%. This suggests that if Hydro hedges foreign exchange exposure associated with fuel oil purchases in isolation without any hedging of the USD commodity price exposure, the volatility of the ratepayer exposure falls negligibly from 30.6% to 30%. In fact, if one assumes there is any degree of positive correlation between the two exposures (if oil prices rise the CAD has a tendency to rise), then it can be shown that the foreign exchange transaction in isolation actually serves to exacerbate the risk in the HFO acquisition cost.

While one might question the efficacy of a foreign exchange hedge in isolation, the same is not true for a commodity hedge in isolation, because of the much higher absolute volatility levels associated with the commodity price. If one hedges the USD commodity price without hedging the foreign exchange exposure in the above example, the volatility of the HFO exposure falls from 30.6% to 6%. Of course if one hedges both exposures in tandem, the volatility falls from 30.6% to 0%.

AUTOMATED VERSUS SUBJECTIVE HEDGING APPROACH

If Hydro chooses to embark on a hedging program, there are two diverging approaches that can be taken with respect to the implementation of the risk management transactions. The automated approach would create a mechanical set of implementation guidelines that would result in the automatic establishment of hedge positions as soon as an exposure is identified within the term of the risk management window. The percentage of underlying exposure to be hedged and the choice of risk management structure to use would be established on an ex ante basis within the risk management Policy. Under this approach, there is no discretion on the part of management to use its judgment of market conditions to adjust the proposed hedging strategy.

The subjective implementation approach would contain an element of subjectivity based on a market price view developed by Hydro's risk management execution team. The market view could be based on any or all of the following: statistical analysis of historical pricing trends, expert forecasts, forward price levels, and fundamental analysis of supply/demand conditions in the HFO market. If the strong view was held that HFO prices will rise above current forward market levels, the most protective hedging strategies would be implemented. In a scenario where a strong view is held that prices will decline, minimal hedges would be established and only those strategy types that retain significant participation in a falling HFO price environment would be used.

Underlying the subjective approach is the assumption that Hydro has the ability to achieve more optimal hedge results by applying its view of anticipated forward market price movements to the risk management process. The main benefit would be the minimization of opportunity costs in a falling price environment. While both approaches would be expected to have significant price protection in place during periods of escalating prices, the aim of the subjective approach is to reduce the amount of price protection that is in place prior to a market price collapse to ensure ratepayer participation in the lower price environment.

RiskAdvisory believes that it is extremely difficult to outperform the oil market (or the currency market) over the long-run unless one has a competitive informational advantage. The ability to outperform markets absent a competitive informational advantage is a rare (and very expensive) skill and not one that one would typically expect to find in the electric utility sector. RiskAdvisory also believes that reliance on external “expert” opinions is also fraught with peril. All of the costly market advisory services have missed significant market movements in the past, and will do so again in the future. Financial counterparties are often incentivized to suggest a certain market direction to encourage the execution of a hedge transaction. It also should be noted that at any given time, for every expert one might find that suggests the market is likely to go up, one can find an expert that believes the market will go down.

This is the fundamental nature of market prices in liquid markets: no matter what the current forward price might be for the commodity, approximately half the marketplace is of the belief that the price will rise and half the marketplace is of the belief that prices will fall. Assume that a commodity has traded in a range between $18 and $22 for a five-year period. A sudden shock causes one-year forward prices to escalate to $30. One might be inclined to believe at this point that there is a much better probability that prices will fall than rise from this level. If one was looking to protect against a further rise in price, one might decide from a price view perspective that this would be an inappropriate point to lock-in a forward purchase. However, if the forward price is currently trading at $30, it is because there are market participants who are buying at $30, all of whom believe the price is likely to rise further. And many of these market participants are professional traders who in fact may have a competitive informational advantage in the marketplace. All participants in this environment will be aware that relative to historical prices, current forward prices appear too high. Yet there are still buyers at the $30 level. If most market participants believed the price should be back at $20, then the forward price would be at $20, not $30. There have been numerous instances in all markets where significant price moves have been followed by even more significant price moves.

An implementation strategy that is based on current price levels versus historic price levels is a price-view driven strategy. While it is not tied to a fundamental interpretation of anticipated supply/demand phenomena, it is what is termed a technical trading approach. Technical traders believe that historical price patterns provide a predictive capability with respect to future price patterns. While technical trading systems can become quite complex, the idea that prices are much more likely to fall than rise if we are currently well above an historic mean is a basic form of technical trading that relies on information about past price behaviour. RiskAdvisory would caution Hydro about the reliability of this type of trading signal – the understanding of historical price behaviour is available to everyone in the market, including professional (and highly-paid) traders. Many of these traders will still be buying even when the price has moved above historical trading ranges.

It is understood that Hydro’s objective is not explicitly to generate profits in isolation on its hedging strategies. Hedges may still be established even if there is a sense that prices are likely to fall. However, under the subjective hedging approach, the choice of hedging instrument would be determined by the market view, with the acquisition of calls more likely than the execution of fixed price swap contracts when the perception is that prices will fall. This approach suggests that over time, the pro-subjective implementation strategy will outperform a more automated approach, leading to a reduction in the cost of the hedging program. However, in an environment where Hydro believes prices will fall and calls are acquired instead of a swap, a continued rise in price will create a situation where the pro-subjective approach results in a higher cost than an automated fixed price strategy. In the end, the ability for Hydro to lower the cost of protection vis-à-vis the automated fixed strategy is a function of the degree to which its market views are correct. RiskAdvisory re-asserts that over the long-run it will be a difficult challenge for Hydro to develop market views that are consistently correct (or even correct more than 50% of the time).

RiskAdvisory has perceived that many companies feel they are abdicating a management responsibility if they choose not to base their hedging strategies on price views and gravitate toward an automated, automatic implementation strategy. The RiskAdvisory response is that developing accurate price-directional views on commodity prices is not a requisite core competence of an electric utility. RiskAdvisory does not believe a utility executive can be admonished for stating that he/she has no capability to outperform the market with respect to directional price views. If this is not perceived to be a core competence of the company in the first place, than there should be no sense that a management responsibility is being abdicated.

There is a danger with the subjective approach that Hydro creates the impression from a regulatory perspective that it possesses and should possess a price view capability that allows the Company to outperform an automated strategy over time. The broad outline of the subjective approach may be pre-approved by the Regulator and still leave the Company in a position where it is exposed to a regulatory disallowance. If aggressive hedges are not established because of a bearish Hydro price view prior to a significant escalation in prices, the Regulator and intervenors could easily question the wisdom behind the development of the Hydro price view. With the automated approach, pre-approval by the Regulator and intervenor groups leaves little opportunity for a disallowance in hindsight. As long as Hydro follows the implementation guidelines developed for the automated approach, the hedging program will meet the expectation of the external stakeholders.

BENCHMARKING THE APPROACHES

One might ask the question over time whether the automated approach will outperform the subjective approach. RiskAdvisory understands that Hydro has conducted some historical analysis showing the performance of the subjective approach. The concern with this analysis is that it can be misleading. As any owner of mutual funds recognizes, prior performance provides very little support for future performance. Many traders and investors have had several good years only to see them followed by several years that are, in total, worse than the good years. The acceptance of the subjective approach should only be done if one believes that in the future one has the necessary information and skill sets to outperform the market.

RiskAdvisory is not aware of any empirical work that has been done that outlines the performance of an automated approach. However, intuitively it would seem that if one were hedging for periods out for one year on a consistent basis using swap contracts, one would consistently have predictability around the price expectation for the next year. Price exposure would also be stable within the year, and a later section of this report will illustrate that year-over-year stability is also enhanced through a rolling implementation of an automated hedging strategy.

EXAMPLE OF THE AUTOMATED IMPLEMENTATION APPROACH

The two key elements to the automated implementation will be the time in advance of actual delivery that hedges will be implemented, and the percentage of forecast exposure that will be hedged.

The Timing of Implementation

Assume that Hydro determines that a 15-month window represents the maximum desired hedging timeframe on behalf of utility ratepayers. Implementation could follow on either a monthly or a quarterly basis. If a monthly basis is chosen, then as soon as a forward exposure moves into the 15th-month timeframe, the exposure would be hedged to a stated percentage. For example, assume a 100,000 bbl exposure is forecast for June 2004, and that 50% of underlying exposure is the maximum hedge position. Today, in June 2002, no hedging would be required for this exposure. However, as of April 1st, 2003, June 2004 moves into position as the 15th month and a forward purchase of 50,000 bbls would be instituted at that time.

If a quarterly hedge implementation program is chosen, then one would execute hedges on the basis of monthly exposures over a three-month period, with the most distant month having to fall within the 15-month maximum window. Assume 100,000 bbls of forecast exposure for each of January 2004 through June 2004. Once again, no hedging would be undertaken today because the term lies outside the 15-month window. As of October 2002, the January 2004 position becomes the 15th month, but under the terms of the quarterly hedging implementation, no hedging would be done for this period in October because the 3rd month of the quarter lies beyond the 15-month window. In January 2003, the entire 1st quarter of 2004 lies within the 15-month window, so hedges of 50,000 bbls in each of January, February and March would be executed at that time. No further hedging action would be undertaken (unless there is a change in forecast exposure) until April 2003, when 50,000 bbl hedges would be established for each of April, May and June 2004.

The choice of a quarterly implementation strategy versus a monthly strategy is typically a function of forward market liquidity characteristics and the constancy of the underlying exposure from month to month. From this perspective, assuming market liquidity allows and relative pricing is deemed to reasonable (i.e. Hydro is not burdened by higher hedging costs for monthly versus quarterly transactions), RiskAdvisory would suggest that the monthly approach has more merit for Hydro since the Company may have material fluctuations in its HFO exposure from month-to-month which negates the ease of hedging in standardized quarterly blocks. Based on the limited liquidity in the 2.2% HFO market beyond 15 months, RiskAdvisory would recommend that the term of the hedging program be limited to this time period.

Hedging Percentage

There are two components to the selection of the hedge percentage. The first would establish the maximum hedge percentage for forecast exposures. The second would describe any automated tier structure to the establishment of hedge positions. This second component would have a timing aspect as well.

With respect to the maximum percentage to be hedged, this becomes a function of one's perception of the degree of risk aversion among Hydro's ratepayers. If it is felt that ratepayers are unwilling to absorb any kind of rate increase, then a high percentage of forecast exposure would be hedged (75% - 90%). If it is felt that substantial protection is required, but that ratepayers also benefit from some exposure to spot prices both from the perspective of a potential fall in price and to receive appropriate pricing signals, a hedge percentage around 50% could be established. If ratepayers are deemed to be less risk averse, then a smaller maximum hedge position would be selected.

It may be decided that the maximum hedge should not be established as soon as forecast exposures move within the hedge window. Under the automated strategy, market-view driven criteria would not dictate the percentage that is hedged. RiskAdvisory would suggest that the primary driver of a tiered approach rests with forward market liquidity and the accompanying implicit hedge transaction costs. If the forward market exhibited strong liquidity (i.e. narrow bid-offer spreads) throughout the maximum hedge window, there would be little need for the tiered approach, However, 15-month HFO markets will exhibit some liquidity constraints relative to more near-term forward positions. As a result, RiskAdvisory can see the merit in a two-tiered structure that requires the establishment of a certain percentage of forecast exposure as soon as one moves within the maximum time horizon, and then an additional hedge when one moves within a second time horizon.

For example, assume a monthly hedge implementation program with a 50% maximum hedge position. Once again, assume a 100,000 bbl forecast exposure in June 2004. In this scenario, 50% of the maximum hedge is required to be established at the 15-month time horizon, and the residual 50% is required to be established at the 12-month time horizon. In this case, one would establish a hedge on 25,000 bbls in April 2003 for this June 2004 exposure, with an incremental 25,000 bbl hedge established in July 2003.

There may be a concern that the establishment of a high hedge percentage could lead to instances where Hydro finds itself more than 100% hedged because of adjustments in fuel requirements (either timing or quantity). From a theoretical perspective, the most effective way of achieving one's risk tolerance is to apply the desired hedge percentage to the expected volumes, and then adjust hedge volumes as changes are made to the fuel requirements. Assume that the desired risk appetite is to be hedged 80%, but the possibility exists that one might end up being 105% hedged or 55% hedged if one hedges current expected volumes, because of potential changes in fuel requirements. Also assume equal probability of any of these scenarios occurring. The mean expectation is that one will be 80% hedged, matching the risk appetite. If instead one lowers the hedge percentage to 75% to ensure no physical overhedge, the mean expectation is that one will be 75% hedged, falling below the desired 80% level.

Despite the theoretical arguments supporting the fact that one should not be concerned about being overhedged if the hedge was initially established on the basis of an expected volume, in practice most companies continue to be concerned about the external perception of an overhedged position. As a result, there does tend to be an element of conservatism in the establishment of the hedge percentage, resulting in a modest downward bias in the hedge percentage relative to the percentage dictated solely on the basis of risk appetite.

Also, it should be noted that if one must adjust a hedge position because of a change in the timing of the delivery of a fuel oil cargo, one can move the hedge from the initial month of protection to the alternate month through a HFO forward spread transaction. Under this type of transaction, one could sell the initial month (closing out part or all of that position) and simultaneously purchase the alternate month with the same counterparty. Because of the liquidity characteristics of spread markets, one will often find that the bid/offer on the spread position is actually less than the bid/offer on just one leg of the outright position. In a marketplace where the bid/offer on a forward fuel oil monthly price might be $0.20, it would not be surprising to see the bid/offer on the spread between this forward month and the next forward month to be around $0.10 per bbl.

Selection of Hedging Instrument

The automated approach would involve an automated hedge instrument selection process, one that is not contingent on Hydro's price view. Keep in mind that the hedging is being done on behalf of Hydro's ratepayers. Hydro's management (and the regulator) need to assess what they believe is the appropriate risk profile desired by their constituents. If it is felt that ratepayers are willing to absorb an incremental upfront cost in order to retain more significant participation in a downside price move (without knowing whether prices are going to rise or fall), then some form of call structure strategy would be recommended. If the perception is that ratepayers would like to lock-in the best possible forward price today while forfeiting any downside participation, then a forward purchase or swap program would be the most suitable. A perception of risk aversion that lies between these two points would suggest some form of collar structure.

The table below provides an indication of sample automated hedging guidelines based on the perceived risk aversion of the ratepayer:

Degree of Risk Aversion	Percentage Hedged	Strategy	Upside Protection	Potential for Material Hedge Losses
High	60% - 80%	Primarily Swaps	Highest	Highest
Mid-Range	40% - 70%	Balance between swaps, caps and collars	Mid-range	Mid-range
Low	25% - 50%	Balance between caps and collars	Lowest	Lowest

The swap alternative would minimize any complexity in the hedge implementation process. Once the hedging percentages and time horizons have been established, swaps are executed automatically. In the case of calls and collars, there is the added issue of a multitude of strike price combinations and premium costs. In order to retain the automated approach, standardized rules can be established in one of two ways. First, one could acquire calls (or establish collar structures) with the call a fixed amount (either dollar amount out-of-the-money or percentage). For example, the policy might read that Hydro must acquire calls $1 out-of-the-money vis-à-vis the monthly forward price being hedged. Similarly, one might require that calls 5% out-of-the-money be acquired.

An alternative would be to establish a per barrel cost that can be expended on calls or collars. On the call side, this is a uni-dimensional constraint. If one is required to spend $0.50 per bbl on the call, then one asks the financial dealers to quote the strike price of the call they would sell for $0.50. With the collar structure, the policy would have to direct both the amount that would be spent and the degree to which the call is out-of-the-money. For example, assume that the policy directed that a $0.20 premium be spent and that a call $1.00 out-of-the money must be acquired. If this call is valued at $0.30 per bbl, then Hydro would be required to sell a put with a strike price that generated a $0.10 premium to offset partially the cost of the call.

The foregoing assumes that markets are sufficiently liquid to provide all the structures in all scenarios. Option liquidity constraints mentioned earlier in this report may force Hydro to use the most cost effective structure available at the point of implementation.

Adjusting Hedge Transactions

The automated implementation approach must include the ability to adjust transactions in the case that underlying forecast exposures change. The fundamental thrust would be that transactions are augmented or reduced whenever a revised forecast creates a change in the forecast HFO exposure. The additional component is that there should be a minimum forecast adjustment amount before a hedge alteration is made to reduce unwarranted transaction costs. For example, one might require a minimum 140,000 bbl adjustment in forecast HFO exposure in any given month (approximately half a cargo) before adjustments are made to a hedge position. Also note that a hedge exposure can be eliminated either by selling the forward position back to the counterparty that executed the initial transaction, or by selling to a different counterparty – the economic effect is the same. However, by selling to a different counterparty, one will be exposed to a credit risk to both counterparties, whereas exiting the position with the initial counterparty will eliminate any credit risk with the position. The advantage of using a second counterparty is that the original counterparty may feel that the transaction is captive if Hydro is looking to unwind the position, and show Hydro a price that is not as competitive as other dealers in the marketplace.

Foreign Exchange

Following on the discussion earlier of the limited impact of foreign exchange transactions in isolation, the automated approach would call for the simultaneous execution of foreign exchange forward transactions with any fixed price HFO transactions. These hedges would be limited to those instances when the HFO price is fixed and known. The term, timing and percentages should be consistent with those established under the HFO hedge implementation policy guidelines. The mechanics are straightforward for HFO swap transactions – as soon as the USD cash outflow is fixed through the swap transaction, an equivalent number of USD are purchased forward to match the cash outflow dates. With caps and collars, the actual USD cash flow is not fixed – it is still subject to a range of outcomes. In these instances, the notional amount of USD purchased forward should match the current forward swap price at the time these transactions are initiated.

REGULATORY CONSIDERATIONS

RATEPAYER RISK APPETITE

The fundamental concept here is that Hydro is acting in effect as agent on behalf of the ratepayers with respect to the implementation of a risk management program around its fuel procurement activities. The Regulator should examine any proposed risk management initiative and determine if it is in the best interest of the ratepayer. The Regulator has stated that it is desirous of rate stability and predictability. If a program can be initiated that contributes to these two objectives, the Regulator should favour the initiative.

In an ideal world, the risk management strategy employed by Hydro would cater to the risk tolerance or appetite for risk of all ratepayers. If the risk appetite suggested that the ratepayer was unwilling to tolerate any further increase in HFO costs, one would design a hedge program that largely insulated Hydro against any fuel cost increase. If the ratepayer was a risk-taker and was willing to accept material increases in costs in return for a reduction in costs in a falling price environment, then one would question the applicability of any kind of fuel oil risk management program for Hydro.

Unfortunately, it is a difficult if not impossible task to identify the risk appetite of the ratepayer. First, this concept of risk management is often difficult for many to grasp and so it becomes a challenge to elicit the ratepayer view on risk appetite. Second, different ratepayers will have different risk appetites. These difficulties have been borne out in other jurisdictions, most notably Manitoba. Centra Gas Manitoba has conducted both telephone surveys and focus group studies in an effort to identify the ratepayer risk appetite. While some general information was gleaned from these studies, the sample sizes were not significant enough to be statistically valid for the customer groups, and the complexities of the risk management issue were extremely difficult to communicate through telephone surveys.

STAKEHOLDER COLLABORATION

As a result, it is left to the larger intervenors, the Regulator and the regulated utility to reach a consensus on the expected risk appetite of the investor. The Regulator has already espoused the principles of stability and predictability as being appropriate objectives and serve the interest of ratepayers within the context of overall regulation but not at any cost. It is imperative therefore that there be a strong collaborative effort between all interested parties to share their views on ratepayer desires and risk management program parameters in order for the program to have any chance of long-term success.

From the Regulator's standpoint, it would be appealing if the regulated utility was charged with the responsibility to forecast future prices accurately, and could therefore time the entry into risk management transactions to maximize protection and minimize downside opportunity costs. However, it is unrealistic and inequitable for regulators to expect that the prudent management of the utility should include the ability to outperform commodity markets. Given that these markets are very difficult to predict, the Regulator should ask itself whether it is desirable to have the utility base its hedge implementation strategy on its price views. Knowing that even the best commodity traders have losing stretches and that Hydro is a small player in the global HFO market with little in the way of a competitive informational advantage, the Regulator should question the merit of relying on Hydro's market views to influence the outcome of the risk management program.

STAKEHOLDER EDUCATION

There is an onus on the Company to provide a basic level of understanding of the risks and risk management concepts to the Regulator. There are other utilities who have conducted statistical analysis to assign probabilities to potential movements in deferral accounts caused by underlying movements in commodity prices (e.g. Centra Gas Manitoba, ATCO Gas, Idaho Power Company). For example, one might be able to conclude that there is only a 5% probability that the deferral account will rise more than CAD20 million from initial forecasts. This provides the Regulator and interveners with a better understanding of the magnitude of risk in the portfolio. The analysis can also include the effect of proposed hedging strategies with respect to mitigating risk.

The other key component that the Regulator must understand is the potential for material opportunity costs under some hedging strategies. Once again, establishing fixed price hedges on a material component of Hydro's forecast fuel purchases will provide substantial protection against upward rate pressure, but it can lead to significant hedge losses. These losses represent the crystallization of the loss of participation in a falling price environment. The Company must ensure that in hindsight the Regulator and intervenors are not "surprised" by the outcome of the risk management activity.

Related to this issue is the fact that the hedge program should not be benchmarked from the perspective of the gains or losses generated by the hedges in isolation. It must be made clear to regulators and intervenors that the objective of the risk management program is not to achieve the lowest cost for fuel oil purchases (in which gains or losses on hedges in isolation would be benchmarked), but rather to achieve the lowest cost while recognizing the risk appetite of the ratepayers. As mentioned earlier in the review of hedging instruments, the expected gain or loss on swaps, caps or collars over the long-run is zero, less any implicit transaction costs represented by 50% of the bid-offer spread. With an automated hedging strategy, one should anticipate that there will be a net cost to hedging over the long-run. However, to reiterate the goal is not to generate profits on hedge transactions, but to reduce the impact of material swings in HFO prices on the rates charged to Hydro's customers.

RELATED REGULATORY EXPERIENCES

Historically, some utilities have opted to do nothing from a risk management perspective (e.g. ATCO Gas, TransAlta/Utilicorp), often because the regulatory precedent provided the utility with a sound foundation to remain on the hedging sidelines. In these instances, regulators had provided an indication that open exposure for ratepayers was acceptable. Many other jurisdictions historically have applied a subjective approach (Centra Manitoba, Union Gas, NB Power, Idaho Power). However, the evolution of the risk management activity and ex post difficulties with regulators and intervenors has led many in this latter group to move to an automated implementation program (Centra Manitoba, NB Power, Idaho Power). In each of these cases, the utility has stated that it does not have the ability to outpredict the market and the regulators have accepted this assertion. Rather than leave the door open for hindsight criticism of the risk management activity, each of these utilities has received at least tacit upfront approval from its regulators and in some instances with intervenor groups to pursue a clearly-defined automated hedging strategy.

Benefits of an Automated Hedging Strategy to Hydro and Its Ratepayers

There are several benefits of the automated hedging strategy to Hydro and its ratepayers. From Hydro's perspective, the automated strategy with some degree of pre-approval from the Regulator and intervenors assures stakeholder comfort with the program and lessens the likelihood of a critical hindsight review. With a subjective hedging strategy, ratepayers' interests may not be served in an environment where prices escalate and less aggressive hedge strategies have been implemented. The consistent implementation of the automated strategy following the automated guidelines established in policy reduces the likelihood of negative surprises for the Regulator and ratepayers.

Rate Predictability and Stability

The automated strategy also assists Hydro with meeting the Regulator's twin objectives of rate stability and predictability in serving the interests of ratepayers. There is an issue as to whether the protection sought in this objective is already achieved through the existence of the Rate Stabilization Program ("RSP"). The RSP serves to eliminate ratepayer exposure to market movements (and the hydrology effect) within a rate year. However, ratepayers are exposed to an increase in rates in subsequent years from two effects. First, higher fuel costs in Year 1 will lead to a rate increase for years 2 and 3 as the RSP balance is amortized over this period. Second, if the forecast fuel oil price increases from Year 1 to Year 2 and Hydro applies for a rate hearing, the year-over-year increase in the forecast price could also be absorbed by ratepayers. For example, assume fuel oil averages $25 in 2002 matching initial expectations and then climbs to $30 in 2003. If 2003 is deemed to be a test year for regulatory purposes and rates are adjusted to reflect the higher fuel oil cost component, then ratepayers would be exposed to all of this $5 increase in 2004. In the end, the RSP serves to dampen the effect of fuel oil volatility, but this effect is not eliminated. Even with the RSP, there is a likelihood that there will be an adjustment in next year's predicted rate, and that there can be instability in rates from year-to-year. The establishment of a risk management program with a rate year term will serve to insulate ratepayers against the effect of higher rates caused by the amortization of the RSP balance. A risk management program which extends beyond the current rate year term can serve to lessen the likelihood of a year-over-year rate increase caused by higher fuel prices even inclusive of potential hedge losses versus an unhedged position where fuel prices could increase dramatically.

It should be clear that an automated hedging strategy will increase predictability. If one is employing a 15-month hedge window, then Hydro will enter each new fiscal year with a high degree of predictability around the effect on the RSP balance from the HFO acquisition activity. In fact, for planning purposes much of the annual forecast fuel oil expenditure will be known in October prior the start of the fiscal year. Unexpected movements can occur to the extent that collars or caps are used instead of swaps, and to the extent that less than 100% of the forecast fuel oil exposure is hedged. (The RSP balance of course will still be a function of hydrological input factors). With a subjective implementation process, a view that HFO prices are likely to soften would reduce the degree to which price certainty had been established, with a concomitant reduction in predictability.

The issue around rate stability is more complex. The RSP ensures rate stability within the year. However, rates can change year-over year if excess RSP balances need to be recovered. Rate instability can be caused by year-over-year changes in fuel costs. If HFO prices average $26.00 in one year and $30.00 the following year, then ratepayers will incur a rate increase in order to recoup part of the RSP balance in the third year. If HFO prices escalate to $35.00 during the third year, there will be another rate increase in year four.

The key to determining whether one fuel acquisition strategy creates more stability than another rests on the potential year-over-year change in fuel prices under each strategy. In the case of a strategy where hedge transactions are not used to lock in forward prices, the ratepayer is exposed to year-over-year movements in the spot CAD HFO price. In other words, how will the January 2004 spot price compare to the January 2003 spot price? How will the February 2004 spot price compare to the February 2003 spot price? This comparison continues through the course of the year. Now assume for simplicity a program where forward HFO requirements are hedged with a 12-month rolling window. In this scenario, the January 2003 price is actually established in January 2002 when one enters into the fixed price 12-month transaction for January 2003. Likewise, the January 2004 price is established in January 2003 when one enters into the 12-month fixed price forward position for January 2004. In order to determine which approach is likely to be more stable, one has to ask whether the movement in the forward January 2004 from January 2003 until January 2004 becomes the spot price will be more volatile than the movement in the January 2004 forward between January 2002 (when it is trading as the 24th forward month) and January 2003 (when it is trading as the 12th forward month). As was stated in the discussion of the HFO commodity section earlier in the report, prices at the front end or nearer months of the forward curve tend to be more volatile than prices at the back end or longer-dated months of the forward curve. Recent volatility indications received from the marketplace indicate that the anticipated volatility in a 12-month forward from today through to spot is approximately 30%. At the same time, the anticipated volatility in the 24th month for the next twelve months is in the range of 15% to 20%. This indicates that by shifting the timing of the establishment of a fixed price for HFO from a spot purchase program to a program that fixes the price twelve months out (or fifteen months out) will serve to increase the year-over-year stability in HFO costs, which in turn will lead to more stability in RSP balances and rates.

RiskAdvisory believes that the fuel oil hedging program should not be viewed as a replacement to the RSP – if the prices that were established through hedge transactions for year 2 are greater than those established in year 1, ratepayers will still be exposed to higher prices. RiskAdvisory views the hedge program as complementary to the RSP, with the combination of the two initiatives yielding the highest probability for rate stability and rate predictability.

RECOMMENDATIONS

RiskAdvisory recommends that Hydro consider whether the incremental improvement in price volatility that would result from the implementation of an oil hedge program, warrants the costs and risks associated with its introduction, when viewed in the context of the current Rate Stabilization Plan.

In the event that Hydro elects to implement an oil hedge program, RiskAdvisory would strongly recommend the automated approach over the subjective approach. The subjective approach pre-supposes a Hydro ability to outperform the HFO market over the long-run. Hydro's lack of competitive advantage on this front combined with the regulatory environment where decisions based on price view will always be open to negative hindsight review favours the automated approach.

RiskAdvisory would recommend a collaborative approach with regulators and major intervenors with respect to the establishment of guidelines around the program. The following steps should be undertaken:

- Workshop session with the Regulator and major intervenors to explain:
    - the magnitude of the HFO exposure to ratepayers and the potential impact on rates;
    - the basic hedging structures available;
    - Hydro's role as "agent" for the ratepayers in the process;
    - the merits of the automated versus subjective approach;
    - the need for a consensus around ratepayer risk appetite;
    - the fact that significant losses may accrue on hedge positions established under the program;
    - the fact that the risk management program will not be benchmarked on gains and losses.
- Development of a consensus around the risk appetite of the ratepayer;
- Selection of guidelines with respect to hedging percentages and the choice of hedge instruments;
- Approval of the hedge window.

RiskAdvisory recommends seeking as much pre-approval as possible surrounding the hedge guidelines from the Regulator and major intervenors.

RiskAdvisory would recommend a 15-month hedge window based on liquidity considerations.

RiskAdvisory recommends that foreign exchange hedges be established only in conjunction with the execution of HFO hedge transactions. This eliminates the potential for the establishment of ineffective currency hedges from a risk reduction perspective.

RiskAdvisory recommends the inclusion of a Performance Measurement section in the Risk Management Policy that explicitly excludes the profit or loss on hedge transactions in isolation from the performance measurement process.

APPENDIX III

POLICY AND PROCEDURE

NO. 2 AND NO. 6 FUEL MANAGEMENT PROGRAM

NO. 2 AND NO. 6 FUEL MANAGEMENT PROGRAM

The Corporation shall purchase, store and use No. 2 fuel for its diesel and Gas Turbine Generating Stations and at Holyrood as ignition fuel for the main boilers, and No. 6 fuel oil for its Holyrood Generating Stations at lowest cost with due consideration for maintaining a secure supply for meeting customer demand and energy requirements and due consideration of the environment. The Vice President - Production has overall responsibility for the successful execution of the No. 2 and No. 6 Fuel Management Program.

NO. 6 FUEL OIL

1.0 Procurement, Delivery and Inventory Management

Manager- Administration

1.1 Prepares tendering documents for procuring fuel in consultation with Vice President – Production, Manager – System Operations, Manager – Thermal Generation and Senior Legal Counsel. The supply contracts will run a minimum of three years with a possible extension two years before re-tendering.

1.2 Obtains competitive bids to supply fuel in accordance with tender documents.

1.3 Reviews the results of fuel tenders with Vice President – Production, Manager – System Operations, Manager – Thermal Generation and Senior Counsel and awards the tender to lowest bidder who meets the fuel tender specifications.

Manager – System Operations

1.4 Provides the Manager – Administration with fuel delivery requirements based on forecast production levels at Holyrood and fuel oil storage requirements for production security, which considers seasonal icing in Conception Bay, load forecast and hydraulic reserves.

Manager – Administration

1.5 Places orders for fuel deliveries as per System Operations request with the fuel oil supplier.

1.6 Tracks progress of deliveries and notifies Manager – Thermal Generation, Manager- System Operations and Treasurer of the delivery quantities and times.

1.7 Arranges fuel testing as required under the fuel supply contract to ensure compliance with the specification.

1.8 Provides fuel-testing results to Manager- System Operations, and Manager – Thermal Generation.

1.9 Notifies the supplier of non-conformances found in tests and indicates action to be taken as provided in the supply contract.

Treasurer

1.10 Arranges adequate amount of U.S. funds to be available to cover the cost of delivered fuel.

Manager – Thermal Generation

1.11 Arranges for fuel offloading, storage of fuel and measurement of quantity delivery.

1.12 Arranges for and reports weekly fuel inventory levels to Manager – Administration and Manager – System Operations.

Manager – Administration

1.13 Receives, verifies and arranges fuel supplier invoice payments.

2.0 Budget Forecasting and Cost Control

Manager – Economic Analysis

2.1 Provides periodic short-term load forecast to Manager of System Operations.

2.2 Provides a forecast of No. 6 fuel prices to Manager of System Operations.

Manager – System Operations

2.3 Forecasts production requirements at Holyrood and estimates fuel usage based on historic Holyrood efficiency levels and other factors influencing production requirements such as the load, hydraulic production, and power purchase forecasts.

2.4 Forecasts fuel delivery requirements based on minimum inventory requirements throughout the forecast period with due consideration of Conception Bay icing forecast.

2.5 Forecasts the monthly fuel purchase costs and production costs.

2.6 Tracks and reports the actual monthly fuel consumption, Holyrood plant efficiency and cost implications of variances in efficiency.

Performance Specialist - Holyrood

2.7 Review fuel use and energy production on a unit-by-unit basis at Holyrood to ensure optimum production per barrel of fuel used and initiate appropriate actions to maximize, insofar as possible such production per barrel consumed.

3.0 Fuel Market Monitoring and Strategic Purchasing

Manager – Administration

3.1 Monitors market fuel prices daily and reports market prices weekly.

Management Committee

3.2 Reviews market fuel prices and confers with the Manager – System Operations when a strategic purchase can be undertaken given committed shipments, inventory levels and storage capability.

Manager – System Operations

3.3 Requests the delivery of the strategic purchases as per the Management Committee direction.

NO. 2 FUEL OIL

4.0 Procurement, Delivery and Inventory Management

Manager- Administration

4.1 Prepares tendering documents for procuring fuel in consultation with Vice President – Production, Manager – System Operations, Senior Supervising Mechanical Engineer- Generation, Regional Managers – TRO and Senior Legal Counsel.

4.2 Obtains competitive bids to supply fuel in accordance with tender documents.

4.3 Reviews the results of fuel tenders with Senior Supervising Mechanical Engineer, Regional Managers – TRO and Senior Legal Counsel and awards the tender to the preferred bidder who meets the fuel tender specifications. This account may be split and awarded to several vendors to optimize cost minimization recognizing geographical and shipping economies.

Manager – Economic Analysis

4.4 Provides the Manager – Administration with pre-winter fuel oil storage requirements for isolated diesel systems based on forecast production levels for the respective systems and production security.

Manager – System Operations

4.5 Provides the Regional Managers – TRO with the minimum inventory requirements at each of the Standby plants on the interconnected systems based on forecast production levels and potential emergency requirements for system security reasons.

Manager - Administration

4.6 Consults with suppliers and with designated individuals listed on Schedule A to ensure deliveries to coastal plants where winter deliveries are not possible are scheduled for late Fall prior to ice formation and for Spring immediately following ice breakup.

4.7 Maintains list of designated positions for each plant or area, as indicated in Schedule A.

Designated Positions (Schedule A)

4.8 Monitor fuel usage by Location and request deliveries, as required, from supplier.

Regional Manager TRO or Manager – Thermal Generation

4.9 Arranges for fuel offloading, storage of fuel and measurement of quantity delivery.

Manager – Administration

4.10 Receives, verifies and arranges fuel supplier invoice payments.

5.0 <u>Budget Forecasting and Cost Control</u>

Manager – Economic Analysis

5.1 Provides a forecast of No. 2 fuel prices for each generating plant using No. 2 fuel to the Manager, System Operations.

5.2 Provides a forecast of fuel cost for all Isolated Diesel Systems based on the load forecast and projected fuel efficiencies of each diesel plant.

Manager – System Operations

5.3 Determines the production requirements of the Interconnected generating stations using No. 2 fuel.

5.4 Provides a forecast of fuel costs for all Interconnected generating stations using No. 2 fuel. This includes a forecast of ignition fuel requirements at the Holyrood Generation Station.

5.5 Monitors No. 2 fuel usage and costs, re-forecasts costs based on expected changes in requirements or variances in fuel price forecasts.

6.0 <u>Fuel Market Monitoring and Strategic Purchasing</u>

Manager – Administration

6.1 Monitors market fuel prices and reports market prices weekly.

6.2 Adjusts Contract Price up or down, cent for cent with changes in the mean of the Montreal price for diesel fuel for Island and Standby Systems and Stove Oil for Labrador System, as published in Oil Buyers' guide under Canadian Terminal Prices, Rack Contract. The Selling Price is adjusted, if necessary, every sixty (60) days.

Schedule A
Persons and Alternates Who Notify
Manager, Administration Of Fuel Needs

		Location	Fuel Type	Notification to Manager of Administration by
1		Holyrood	No. 6	R. Henderson/D. Harris
2		GT Holyrood	No. 2	A. Pollard/W. Rice
3	Labrador Region Happy Valley-Goose Bay	Black Tickle	No. 2	Rod Cabot, Production Supervisor
4		Cartwright	No. 2	Rod Cabot, Production Supervisor
5		Davis Inlet	No. 2	Rod Cabot, Production Supervisor
6		Hopedale	No. 2	Rod Cabot, Production Supervisor
7		Makkovik	No. 2	Rod Cabot, Production Supervisor
8		Mud Lake	No. 2	Rod Cabot, Production Supervisor
9		Nain	No. 2	Rod Cabot, Production Supervisor
10		North Plant HVGB	No. 2	Rod Cabot, Production Supervisor
11		GT HVGB	No. 2	Rod Cabot, Production Supervisor
12		Paradise River	No. 2	Rod Cabot, Production Supervisor
13		Postville	No. 2	Rod Cabot, Production Supervisor
14		Rigolet	No. 2	Rod Cabot, Production Supervisor
16	Northern Region Port Saunders	Charlottetown	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
17		Hawke's Bay	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
18		Mary's Harbour	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
19		L'Anse au Loup	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
20		Norman Bay	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
21		Port Hope Simpson	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
22		St. Anthony	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
23		St. Lewis	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
24		Roddickton Therm Pl.	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
25		William's Harbour	No. 2	Kirby Spence, Term. St. & Gen. Superintendent
26	Central Region Bishop's Falls	Francois	No. 2	Dale Head, Substitute Production Supervisor
27		Grey River	No. 2	Dale Head, Substitute Production Supervisor
28		Lapoile	No. 2	Dale Head, Substitute Production Supervisor
29		Little Bay Islands	No. 2	Dale Head, Substitute Production Supervisor
30		McCallum	No. 2	Dale Head, Substitute Production Supervisor
31		Petites	No. 2	Dale Head, Substitute Production Supervisor
32		Ramea	No. 2	Dale Head, Substitute Production Supervisor
33		Rencontre East	No. 2	Dale Head, Substitute Production Supervisor
34		St. Brendans	No. 2	Dale Head, Substitute Production Supervisor
35		GT Hardwoods	No. 2	Wayne Snow
36		GT Stephenville	No. 2	Bernard Hartery

Newfoundland and Labrador Hydro

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Island Hydrology Review
Final Report

Prepared by
SGE Acres Limited

January 2003
P14503.00

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List of Tables

List of Figures

Glossary

Board	- Board of Commissioners of Public Utilities of Newfoundland and Labrador
EC	- Environment Canada
Extension Report	- Report on the Extension to the Power Generation Facility at Bay d'Espoir
FERC	- (U.S.) Federal Energy Regulatory Commission
HIRMIG	- Hydraulic Integrated Resource Management Interest Group
Hydro	- Newfoundland and Labrador Hydro
Interim Report	- Interim Report on the Upper Salmon Development – Victoria Lake Diversion - Lloyds River Diversion
LOWESS	- Locally Weighted Regression Scatterplot Smoothing
NAO	- North Atlantic Oscillation
NERC	- North American Electric Reliability Council
NLCP	- Newfoundland and Labrador Power Commission (Hydro's Predecessor)
PPCC	- Probability Plot Correlation Coefficient
Prewhitening	- Removal of Autocorrelations in a Time Series
RFP	- Request for Proposals
RHBN	- Reference Hydrometric Basin Network
RSP	- Rate Stabilization Plan
Stage II Report	- Report of Stage II Diversion and Power Development Extensions for Bay d'Espoir Development

Summary

During the course of the 2001 General Rate Application by Newfoundland and Labrador Hydro (Hydro), attention was focused on the reliability and appropriate length of hydraulic record used in developing the estimated annual hydraulic production from Hydro's hydroelectric facilities. In its ruling (P.U. 7 (2002-2003)), the Board of Commissioners of Public Utilities of Newfoundland and Labrador directed Hydro to commission a study of hydrological issues related to estimation of hydraulic energy production. SGE Acres was retained by Hydro to perform this study under the terms of reference approved by the Board.

The main purposes of the study were to review Hydro's data and methodology for estimating annual hydroelectric capability on the Island of Newfoundland, and to recommend the most appropriate length of record to use to develop the estimate. In addition, the study addressed the possibility of trends in streamflow, the effect of climate change on generation, and practices in other jurisdictions.

An important part of the work was the assessment of streamflow data, in particular looking for trends. Hydro uses reference inflow series for the seven rivers contributing water to its hydroelectric projects on the Island. In general the lengths of the series are 50 years or more. For the years before the projects were built, the inflow series were developed using streamflow data from other sources, primarily Environment Canada. For the years since the projects were constructed, the series were developed from Hydro's operational data.

The conclusion of the assessment was that the data used to construct the inflow series are generally valid. Three of the seven inflow series, however, have some minor internal inconsistencies arising from the change in methods used to develop the inflow series before and after construction of the projects. The inconsistencies would have only a small effect on the estimates of average energy, but the inflow series should be corrected. Hydro would then have a complete set of consistent inflow series at least 50 years long for all of its hydroelectric stations.

Analysis of Hydro's inflow series and records from other gauged basins on the Island did not show any definitive trends or changes. Research on climate change in the region has yet to provide a conclusive indication of how climate change may affect hydraulic generation. The inflow series show the characteristics of random series, which means that the best estimate of future flow, whether next year's flow or the flow over a longer period in the future, is the long term average value. The longer the record, the better the estimate of this average value.

Hydro's inflow series are used to calculate expected energy production from its hydroelectric generating stations. The average flow is multiplied by an appropriate energy conversion factor that is unique for each generating plant, and

items such as spill and environmental releases are taken into account using historic values. The review of the methodology for calculating expected energy production concluded that computer simulation of the system would be a more suitable method for calculating the estimate, since it would allow clearer accounting for spills and other releases, as well as for changes in operation. Once the best estimate of average annual energy is made, it should be used for all of Hydro's operations, planning and rate setting purposes.

The findings of this study are consistent with practices in other jurisdictions, as determined by a survey of utilities and regulators.

1 Introduction

SGE Acres was retained by Newfoundland and Labrador Hydro (Hydro) to review the hydrology of the Island of Newfoundland, as it relates to the data used by Hydro in its estimates of annual hydroelectric capability. The main purposes of the study were

- to review Hydro's data and methodology for estimating annual hydroelectric capability for production, forecasting and rate setting purposes, and
- to recommend the most appropriate length of record and methodology to develop the estimate.

Additional items in the scope of work included addressing the possibility of trends and climate change, and providing an overview of practices in other jurisdictions.

A copy of the scope of work provided by Hydro is included as Appendix A.

1.1 Background

The present work arose from a rate hearing held before the Board of Commissioners of Public Utilities of Newfoundland and Labrador (Board) in 2001. One of the inputs into the rate calculation is the average capability of Hydro's hydroelectric generating stations, that is, the average energy that Hydro can expect from those stations.[1] The energy estimate used to set the current rates is not updated from one rate hearing to the next.

The estimate of annual energy from the hydro stations used in rate setting is an expected value. Because hydro generation depends on river flows the actual energy in any year is always different, either higher or lower than the estimated value. The Board uses a mechanism called the Rate Stabilization Plan (RSP) to balance the effects of wet and dry years. Each month the actual production is compared to the expected value. If the hydroelectric production is higher than expected due to wet conditions, the fund will accumulate a credit; if it is lower due to drier conditions, the credit will decrease. In either case, the RSP ensures that the consumer pays for the actual production over the period from one rate hearing to the next. (The RSP is also used to balance other variables, such as the price of fuel oil, that are outside the scope of this study.)

The estimate of energy from the larger hydroelectric stations is currently calculated by multiplying the average amount of usable water by an energy conversion factor for each generating station. The present report deals with the

[1] For the purposes of this report, the term average refers to the arithmetic average and is used interchangeably with the term expected value.

amount of usable water, and the methodology for calculating the energy estimates, and not with the energy conversion factors. For several smaller systems (total of less than 1 percent of Hydro's generation) the historic average generation is used as the estimate.

At present, Hydro makes the energy estimate using the average value of long hydrological sequences (over 50 years) to determine the amount of water for energy production. Some questions arose at the 2001 rate hearing concerning the inflow data and lengths of the sequences, and the Board requested Hydro to carry out this review of the hydrologic data and related issues. As an interim measure, pending the results of the present study, the Board instructed Hydro to use inflows based on the last 30 years in its calculations of average energy.

The main reason that questions were raised about the average energy estimate is that credits have been accumulating in the RSP for most of the 1990s, due to a series of wet years. This accumulation reflects the fact that the estimate used to set the base rates is low relative to production in those years. It is appropriate to assess the data that Hydro has been using to calculate the estimate, particularly in light of possible climate change.

The data assessment addresses several related questions.

- Are the actual flow measurements accurate, either on natural rivers or at Hydro's stations?
- If the records are accurate, do they suggest the possibility of trends in the records? Do the wet years of the 1990s indicate a sustained trend in streamflow, possibly the result of climate change?
- Is there a possibility that the records show differences in flows before and after the projects were constructed, i.e., are the pre and post project inflows consistent? Might any apparent trends actually be step trends resulting from different methods used to develop the inflow sequences before and after the projects were constructed?

Once the inflow data have been assessed, it is also appropriate to review the methodology used to convert the inflows to energy, since it is the energy value that is used to set the rates.

The calculated value of average energy is also used for Hydro's internal use, for such purposes as generation expansion planning and annual fuel purchase planning. For these purposes the same method is used as for setting the rates, but for system planning and forecasting of fuel purchases the estimate is updated annually.

For day-to-day operations and medium term outlooks (seasonal), Hydro uses a sophisticated computer model with daily inflow sequences. The average value is not relevant. The model provides information for setting reservoir storage targets, given present conditions and load forecasts, and provides guidance to the dispatch center in determining which units to use to meet the day-to-day load. The model uses the same inflow sequences as are used for rate setting, adjusted to a common period of record (1950 and onward).

One of the questions to be addressed in the study is whether the same estimate and methodology should be used for Hydro's planning, operations and rate setting purposes.

1.2 Report Organization

Sections 2 to 4 of this report relate to the data assessment. Section 2 describes Hydro's data, along with other relevant data used for comparison. Section 3 describes the techniques used to assess the data, considering in particular the possibility of trends, and Section 4 discusses the results of the assessment. Section 5 briefly reviews some of the relevant literature on climate change, and looks at the possible effects of climate change on streamflows, and consequent energy generation. Section 6 then describes and assesses the methodology used by Hydro to convert inflows to an estimate of average energy. Section 7 provides an overview of relevant practices in other jurisdictions. Section 8 discusses the issues raised in the study, and Section 9 provides conclusions and recommendations.

2 Description of Data

This section presents the various data sets examined in this study. There are three types of data, as follows.

- Hydro reference inflow sequences.
- Streamflow records from Environment Canada (EC) hydrometric stations.
- Precipitation records from EC meteorological stations.

The most important series are Hydro's reference inflow sequences. Although they are sometimes referred to as data sets, they are actually inflow sequences developed from other data sources. In this section, an assessment of the source data used to prepare Hydro's inflow sequences follows the description of the development of the series.

The other two types of data, EC's natural streamflow and precipitation series, are analyzed in this report for comparison with the Hydro sequences. These data sets are described in this section, but no additional discussion is provided of the quality or data collection techniques for them.

2.1 Hydro Reference Inflow Sequences

Hydro uses reference inflow sequences to estimate the generation capability at each of its hydroelectric plants. Each sequence is a series of inflows, expressed as the annual volume of runoff in each drainage area. The inflows are synthesized or calculated values, not recorded data. The inflows were originally calculated as monthly values, but for capability estimation purposes they are aggregated into annual values. The annual values are used in this study.

The reference inflow sequences extend farther back in time than the existence of the plants themselves. The methods used to synthesize inflows for the periods before and after development are different. In general, the pre-development inflows were synthesized from available records of streamflow measurements, and post-development inflows were calculated by backrouting. The backrouting procedure makes use of recorded turbine flows, spill flows and reservoir levels, and the estimated relationship between reservoir elevation and volume, to solve for the estimated inflows. With each passing year, a new value is added. Prior to Hydro's rate hearing in 2001, years of data were never dropped from the sequences.

There are seven reference inflow sequences, for the five plants on the Island interconnected system. The sequences are

- Victoria;
- Grey;
- Upper Salmon;
- Lower Salmon;
- Cat Arm;
- Hinds Lake; and
- Paradise River.

The Victoria, Grey, Upper Salmon and Lower Salmon drainage areas make up the total drainage area of the Bay d'Espoir development. The Bay d'Espoir development includes the Bay d'Espoir and Upper Salmon plants, and represents the majority of Hydro's hydraulic generation capability on the Island interconnected system. The Cat Arm, Hinds Lake and Paradise River plants make up the remainder.

Summary data for each sequence are provided as Table 2.1. Figure 2.1 shows the locations of the seven drainage areas and the five hydroelectric plants. The reference inflow sequences are presented in Appendix B, shown as annual volumes, with conversions to average flow (m^3/s) and equivalent depth of runoff (mm).

The reference inflow sequences are discussed in the following sections.

2.1.1 Victoria

All of the Bay d'Espoir reference inflow sequences begin in 1950, and each sequence consists of 52 consecutive annual inflows, up to and including 2001.

The Victoria sequence represents inflows in the drainage area of the Victoria Lake reservoir. The reservoir was formed by the diversion of the Victoria River in Stage II of the Bay d'Espoir development.

The sequence can be broken into three distinct periods (two pre-development and one post-development), according to the method of synthesis. The periods and methods are presented in summarized form below.

1950 to 1966
Monthly inflows in the Victoria drainage area to June 1965 are tabulated in the *Report on Stage II Diversions and Power Development Extensions for the Bay d'Espoir Development* ("Stage II Report"), and to September 1965 in the *Interim Report on the Upper Salmon Development—Victoria Lake Diversion—Lloyds River Diversion* ("Interim Report"), both dated 1967 and prepared by ShawMont Newfoundland Limited.

During the 1960s, the Shawinigan Engineering Company prepared flow estimates for ShawMont as part of a comprehensive study on hydro development on the Island of Newfoundland. Maps of mean annual runoff were prepared from analysis of climatic, physiographic and hydrologic information. Mean monthly flows for ungauged sites were then synthesized using correlation and transposition techniques.

According to the Interim Report, the Victoria inflows were synthesized by taking flows observed in the nearby Lewaseechjeech Brook basin and transposing them to the Victoria diversion site. The report indicates that the flows were prorated by the ratio of drainage areas and reduced by 10 percent to account for the lower estimated rainfall in the Victoria basin.

There is an EC hydrometric station on Lewaseechjeech Brook, designated Lewaseechjeech Brook at Little Grand Lake (02YK002). Seasonal records begin in 1952 and continuous records begin in 1956. The available information does not make clear whether these records were used in the synthesis of flows from 1950 to 1965. The correlation of the synthesized and recorded annual flows is good, but not exactly linear. However, it does appear that the flow record was used for the period October 1965 to September 1966 (one year beyond the tabulation in the Interim Report). There is an exactly linear correlation of the monthly flows in this period, which confirms the methodology described.

1966 to 1967

For the period October 1966 to September 1967, an EC hydrometric station was in service downstream of the proposed diversion site. The station was designated Victoria River below Highway Bridges (02YN001). For this period, the Victoria inflows were synthesized by transposing the recorded flows to the diversion site. The recorded flows were prorated by the ratio of drainage areas. This is confirmed by the exactly linear correlation of the synthesized and recorded flows.

1967 to 2001

From October 1967 onward, beginning with the diversion of the Victoria River, the flows were developed by backrouting from site data by Hydro's predecessor, the Newfoundland and Labrador Power Commission (NLPC).

2.1.2 Grey

The Grey sequence represents inflows in the drainage area of Burnt Pond, Granite Lake and Meelpaeg Reservoir. Before 1970, inflows in this area were synthesized in two separate sequences. One was for the Grey River diversion, encompassing Meelpaeg Reservoir, in Stage I of the Bay d'Espoir development. The other was for the White Bear River diversion, encompassing Burnt Pond and Granite Lake, in Stage II. From 1970 onward, when Granite Lake and Meelpaeg Reservoir were connected by Granite Canal, inflows were treated as a single sequence.

Grey River Diversion, 1950 to 1967
Pre-development inflows for the proposed Grey River diversion were synthesized as part of the ShawMont engineering studies for the Bay d'Espoir development during the 1960s. The information provided in the reports does not explain the method of synthesis for the diversion inflows during this period. However, for the period August 1958 to January 1967, there was an EC hydrometric station in service near the diversion site, designated Grey River near Pudops Lake (02ZD001). Analysis of the annual diversion inflows from 1959 to 1966 confirms that they were synthesized by transposing the recorded flows to the diversion site. The recorded flows were prorated by the ratio of drainage areas. The synthesized and recorded flows are closely correlated.

The hydrometric station was removed on March 11, 1967 when work on the diversion cut off the flow.

White Bear River Diversions, 1950 to 1969
Monthly inflows for the White Bear River diversion to June 1965 are tabulated in the Stage II Report, and to September 1965 in the Interim Report. According to the Interim Report, flows for the White Bear River were synthesized by correlation to the average of flows at two EC hydrometric stations, Salmon River at Long Pond and Lewaseechjeech Brook at Little Grand Lake.

There was also an EC hydrometric station on the White Bear River, in service from October 1964 to November 1969, and designated White Bear River at White Bear Lake (02ZC001). The available tabulated inflows for the White Bear River diversion during the overlapping period (October 1964 to September 1965) show an exactly linear correlation with the EC record. This indicates that the station was used to synthesize inflows during this period.

This may have continued beyond the end of the Interim Report study period, to the end of the EC record in November 1969. However, there is a later report which gives an alternative methodology for the period July 1965 to December 1969. This is the *Report on the Extension to the Power Generation Facility at Bay d'Espoir* ("Extension Report"), dated 1974 and prepared by ShawMont. According to this report, the inflows were synthesized by transposing the inflows from the Victoria sequence, with proration according to the ratios of drainage areas and the estimated unit runoff of the two areas. Unfortunately the report does not tabulate the inflows for the White Bear River diversion that would have been synthesized in this manner.

1967 to 2001
The Grey River diversion came into effect in 1967, followed by the White Bear River diversion in 1970, necessitating synthesis of inflows by backrouting. The Extension Report says that from 1970 there was no separation in the estimation of natural flows in the diverted White Bear and Grey Rivers, since there was no measurement of the flow in Granite Canal.

2.1.3 Upper Salmon and Lower Salmon

The Upper Salmon sequence represents inflows in the drainage area downstream of Meelpaeg Reservoir and upstream of the Upper Salmon plant. The Lower Salmon sequence represents inflows in the drainage area downstream of the Upper Salmon plant and upstream of the Bay d'Espoir plant. Before 1983, the Upper and Lower Salmon inflows were synthesized as a single sequence in a single drainage area, formed by the diversion of the Salmon River in Stage I of the Bay d'Espoir development. In 1983, when the Upper Salmon plant came into service, the inflows were calculated as two separate sequences.

Both sequences can be broken into three distinct periods (one pre-development and two post-development), according to the method of synthesis. The periods and methods are presented in summarized form below.

1950 to 1965
Pre-development inflows were synthesized as part of the ShawMont engineering studies for the Bay d'Espoir development during the 1960s. The study reports refer to the hydrometric station located on the Salmon River upstream of the proposed diversion, designated Salmon River at Long Pond (02ZE001). The station was in service from July 1944 to September 1965. In 1949, the station was taken over by EC from its previous operator, the Aluminum Company of Canada. The flows for the period 1944 to 1949 were not used.

The inflows were synthesized by transposing the recorded flows to the diversion site. The recorded flows were prorated by the ratio of drainage areas. This is confirmed by the exactly linear correlation of the synthesized and recorded flows.

1965 to 1982

After the diversion came into operation in 1965, the NLPC synthesized the inflows by backrouting. The Salmon basin inflows continued to be calculated as a single sequence up to and including 1982.

1983 to 2001

From 1983 onward, after the Upper Salmon plant came into service, inflow sequences for the Upper and Lower Salmon areas were backrouted separately.

To differentiate the Upper Salmon and Lower Salmon inflows prior to 1983, the Salmon basin inflows were retroactively apportioned to the two sequences, according to the ratios of the drainage areas to the total drainage area.

2.1.4 Cat Arm

The Cat Arm sequence represents inflows in the drainage area of the Cat Arm plant. The sequence begins in 1930 and consists of 72 consecutive annual inflows, up to and including 2001. The plant came into service in August 1985, and is located on the Great Northern Peninsula near Great Cat Arm. From September 1968 to December 1982, there was an EC hydrometric station located in the drainage area, designated Cat Arm River above Great Cat Arm (02YF001).

The sequence can be broken into four distinct periods (three pre-development and one post-development), according to the method of synthesis. The periods and methods are presented in summarized form below.

1930 to 1959

The synthesis of monthly pre-development inflows is described in the *Feasibility Report on the Cat Arm Development*, prepared by ShawMont Newfoundland Limited. For July 1929 to July 1959, monthly flows at the Cat Arm hydrometric station site were estimated using linear regression of Upper Humber River and Cat Arm River. However, there were 35 missing months of data in the Upper Humber record. These months were infilled by linear regression of Upper Humber River and inflows at Grand Lake (backrouted by the company operating the station). As well, an adjustment was applied to the synthesized Cat Arm flows for April to July of each year to improve accuracy during the spring runoff period. This was done because of the large proportion of runoff which occurs during this period, as a result of snowmelt.

1959 to 1968
For August 1959 to August 1968, monthly flows at the Cat Arm hydrometric station site were estimated using multiple linear regression of Cat Arm River, Upper Humber River, and Torrent River. Again, a similar adjustment was applied to the flows for April to July.

1968 to 1982
For September 1968 to June 1979 (the end of the report's study period), in-stream flow measurements were taken at the Cat Arm hydrometric station. Measurements continued to the end of the station record in December 1982, after completion of the project. The series of synthesized and recorded pre-development flows were then prorated by drainage area to the project site.

1983 to 2001
From 1983 onward, following construction of the Cat Arm development, Hydro synthesized the inflows by backrouting.

2.1.5 Hinds Lake

The Hinds Lake sequence represents inflows in the drainage area of the Hinds Lake plant. The sequence begins in 1927 and consists of 75 consecutive annual inflows, up to and including 2001. The plant came into service in December 1980 and is located in the Grand Lake basin in the western part of the Island. From October 1956 to March 1980, there was an EC hydrometric station located downstream of the drainage area, designated Hinds Brook near Grand Lake (02YK004).

The sequence can be broken into three distinct periods (two pre-development and one post-development), according to the method of synthesis. A summary of the periods and methods is presented below.

1927 to 1956
The synthesis of monthly pre-development inflows is described in the *Feasibility Report on the Hinds Lake Development*, prepared by ShawMont Newfoundland Limited. For July 1926 to September 1956, monthly flows at the Hinds Brook hydrometric station site were estimated by prorating inflows at Grand Lake. The Grand Lake inflows were backrouted by the company operating the station. The proration factor was the ratio of the average Hinds Brook recorded flow to the average Grand Lake inflow between 1956 and 1976. The series of synthesized flows was then prorated by the ratio of drainage areas at the project site.

1956 to 1980
For October 1956 to December 1976 (the end of the report's study period), streamflow measurements were taken at the Hinds Brook hydrometric station. Measurements would have continued to the end of the station record in March 1980, after completion of the report. The series of recorded flows was then prorated by the ratio of drainage areas at the project site.

1980 to 2001
From April 1980 onward, following construction of the Hinds Lake development, Hydro calculated the inflows by backrouting.

2.1.6 Paradise River

The Paradise River sequence represents inflows in the drainage area of the Paradise River plant. The sequence begins in 1953 and consists of 49 consecutive annual inflows, up to and including 2001. The plant came into service in March 1989 and is located near Paradise Sound, Placentia Bay.

The inflow sequence can be broken into pre-development and post-development periods, as summarized below.

1953 to 1988
There is an EC hydrometric station located near the development, on Pipers Hole River, designated Pipers Hole River at Mothers Brook (02ZH001). Pipers Hole River is relatively close to Paradise River, and both rivers flow in a southeasterly direction to Placentia Bay. The Pipers Hole record begins in 1952 and the station is still active.

Correlation with the annual Paradise River inflows up to and including 1988 demonstrates that the sequence was synthesized by prorating the EC flow record. The proration factor was the ratio of the drainage areas, multiplied by the ratio of the assumed mean annual runoff of the two areas.

1989 to 2001
From 1989 onward, following construction of the Paradise River development, Hydro synthesized the inflows by backrouting.

2.2 Assessment of Source Data for Hydro's Series

In general the reference inflow sequences appear to be based on data obtained by reliable techniques, not influenced by technological changes in the methods of collecting the data, at least since 1950.

2.2.1 Streamflow Records

The series for before the projects were built were developed from records from streamflow gauging stations. Since 1950, that is, after Confederation, these gauging stations have been maintained by EC, using consistent technology. All the EC records were obtained by the standard practice of recording water levels and converting them to flow using a relationship based on concurrent measurements of flow and water level. The technology for measuring water levels has changed from chart recorders to digital loggers, so the data processing is more convenient, but there is no change in accuracy. The accuracy of these records depends on the quality of the streamflow metering and of the interpretation of the rating curves used to calculate the flows from the water level records. EC maintains strict quality control of field measurements and data processing and interpretation.

Streamflow records prior to 1950 were contributed by others, so there is uncertainty as to the quality of the records. The Cat Arm sequence was developed mostly from the Upper Humber record; prior to Confederation, this station was maintained by the paper company operating in the region, and it is not clear what technology or methodology it used. The source data for this sequence is thus questionable.

The Hinds Lake sequence prior to 1950 is based on backcalculated inflows to Grand Lake, rather than from a streamflow station. This data is likely to be consistent since it does not depend on streamflow measurements, and the method of backcalculating inflows is unlikely to have changed. This source data is probably good.

2.2.2 Backrouted Records

After Hydro's projects were constructed, the inflows were calculated by Hydro using a standard backrouting approach. The inflow equals the outflow, plus or minus the change in volume of storage in the reservoir, if applicable. The outflow is taken from spillway discharges, gate openings or turbine use, and if the gates or turbines have been calibrated, the outflow volume is accurate. Turbines in particular are very good for flow metering; the accuracy of the best streamflow stations is plus or minus about 10 percent, whereas flows measured at power stations can be accurate to plus or minus three percent. The flows are also measured at exactly the point of interest. The change in storage volume can be obtained from knowledge of the area of the reservoir and its elevation.

Hydro pays close attention to such items as gate curves and unit efficiencies, and in some cases has requested additional measurements to confirm these. The only exception is Paradise River, where the spill, head loss, and efficiency curves used to back calculate the inflows may not have been examined as thoroughly since the station is relatively small.

2.3 EC Streamflow Records

Streamflows are measured and recorded at EC hydrometric stations at several locations on the Island of Newfoundland. Twelve of these stations were chosen for comparison with Hydro's series; eleven of them are part of the national Reference Hydrometric Basin Network (RHBN). The RHBN is a network of hydrometric stations selected by Environment Canada for detecting climate change impacts and variability in Canada's surface waters. Nationwide, the RHBN consists of 243 streamflow and six lake level stations.

The eleven active RHBN streamflow stations located on the Island of Newfoundland were an obvious choice for trend analysis in this study. In general, they are characterized by relatively large drainage areas and long unbroken periods of record. They all have natural flow rivers, free from artificial influences such as diversions and hydroelectric developments.

The station on Lewaseechjeech Brook at Little Grand Lake is not part of the RHBN network but was also chosen for analysis, because of its proximity to the Victoria and Hinds Lake drainage areas, and because its record extends back into the 1950's. There is a block of missing years in the early part of the record.

Summary data for the 12 selected hydrometric stations are presented as Table 2.2. Figure 2.2 shows the hydrometric station locations. The records of annual flow for the 12 stations are tabulated in Appendix C.

2.4 EC Precipitation Records

Precipitation is measured and recorded at EC meteorological stations at various locations on the Island of Newfoundland. Nine stations with long precipitation records were chosen on the basis of geographic distribution and period of record, preferably 50 years or more. Summary data for the nine climate stations are presented as Table 2.3. Figure 2.3 shows the climate station locations. The records of annual precipitation for the nine stations are tabulated in Appendix D.

Table 2.1
Hydro Reference Inflow Sequences Summary Data

Sequence	Drainage Area (km^2)	Period	Sequence Length (yr)	Plant(s)	Installed Capacity (MW)	Year Plant in Service
Victoria	1058	1950 - 2001	52			
Grey	2152	1950 - 2001	52			
Upper Salmon	902	1950 - 2001	52	Upper Salmon	84	1983
Lower Salmon	1792	1950 - 2001	52	Bay d'Espoir	592	1967
Cat Arm	632	1930 - 2001	72	Cat Arm	127	1985
Hinds Lake	651.1	1927 - 2001	75	Hinds Lake	75	1980
Paradise River	476.5	1953 - 2001	49	Paradise River	8	1989

Table 2.2
EC Streamflow Records Summary Data

Name of Hydrometric Station	ID Number	Drainage Area (km^2)	Period	Record Count
Bay du Nord River at Big Falls	02ZF001	1170	1950 - 2001	49
Gander River at Big Chute	02YQ001	4450	1949 - 2001	52
Garnish River near Garnish	02ZG001	205	1958 - 2001	43
Harrys River below Highway Bridge	02YJ001	640	1968 - 2001	33
Isle aux Morts River below Highway Bridge	02ZB001	205	1962 - 2001	39
Lewaseechjeech Brook at Little Grand Lake	02YK002	470	1952 - 2001	39
Middle Brook near Gambo	02YR001	275	1959 - 2001	42
Pipers Hole River at Mothers Brook	02ZH001	764	1952 - 2001	49
Rocky River near Colinet	02ZK001	301	1948 - 2001	52
Southwest Brook at Terra Nova National Park	02YS003	36.7	1967 - 2001	34
Torrent River at Bristol's Pool	02YC001	624	1959 - 2001	42
Upper Humber River near Reidville	02YL001	2110	1928 - 2001	62

Notes:
1. The stations listed (except Lewaseechjeech Brook) are the active Island of Newfoundland stations of the national Reference Hydrometric Basin Network (RHBN) for climate change analysis.
2. Record Count is the number of annual flows in the record. Incomplete years are excluded.

Table 2.3
EC Precipitation Records Summary Data

Name of Climate Station	ID Number	Period	Record Count
Colinet	8401200	1938 - 1992	37
Corner Brook	8401300	1933 - 1999	58
Daniel's Harbour	8401400	1946 - 1999	30
Deer Lake	8401500	1933 - 1999	44
Exploits Dam	8401550	1956 - 1999	38
Gander International Airport	8401700	1937 - 1999	63
Grand Falls	8402050	1934 - 1999	40
Port aux Basques	8402975	1909 - 1997	54
St. John's Airport	8403506	1942 - 1999	56

Note:
Record Count is the number of annual precipitation totals in the record. Incomplete years are excluded.

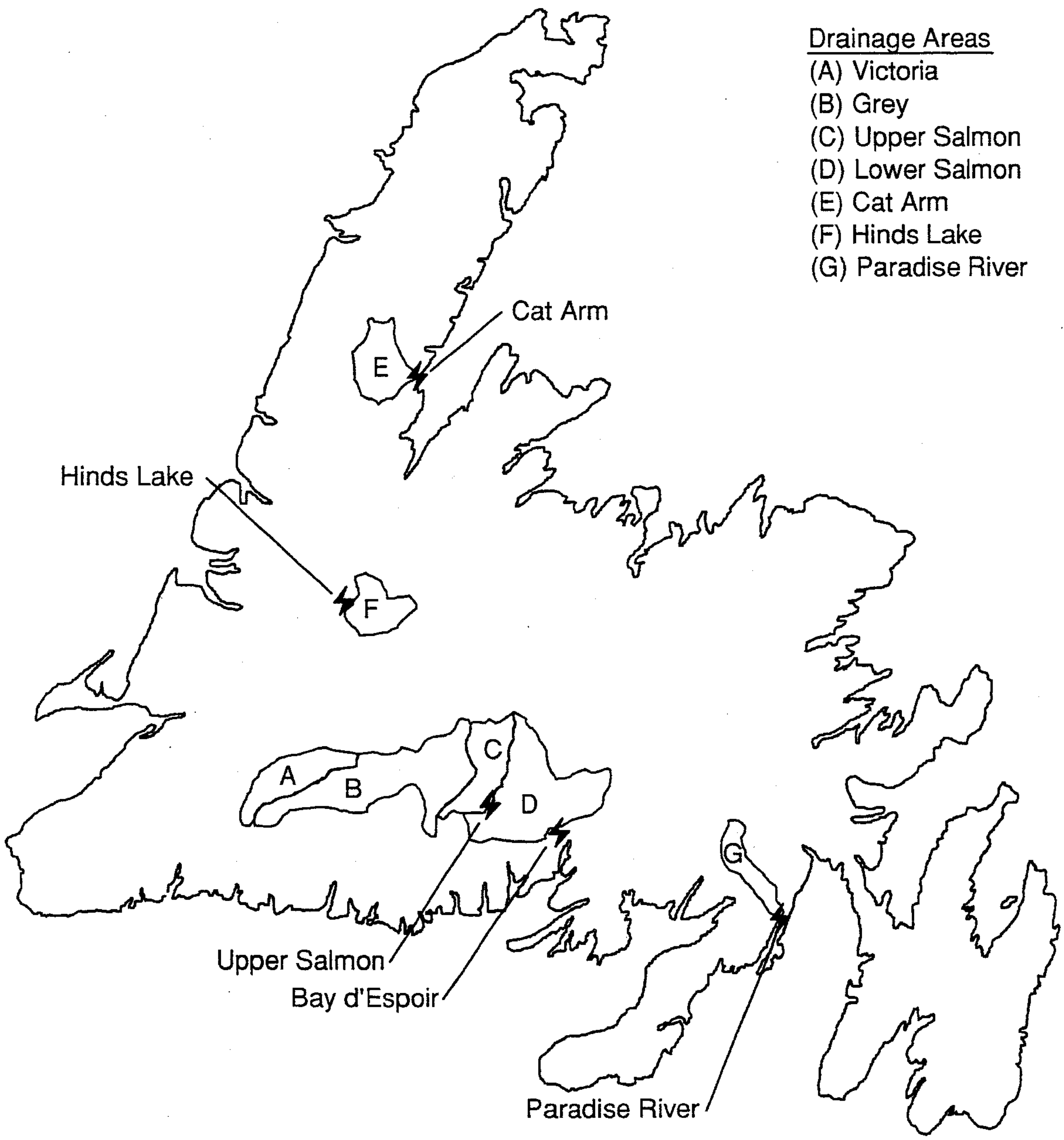
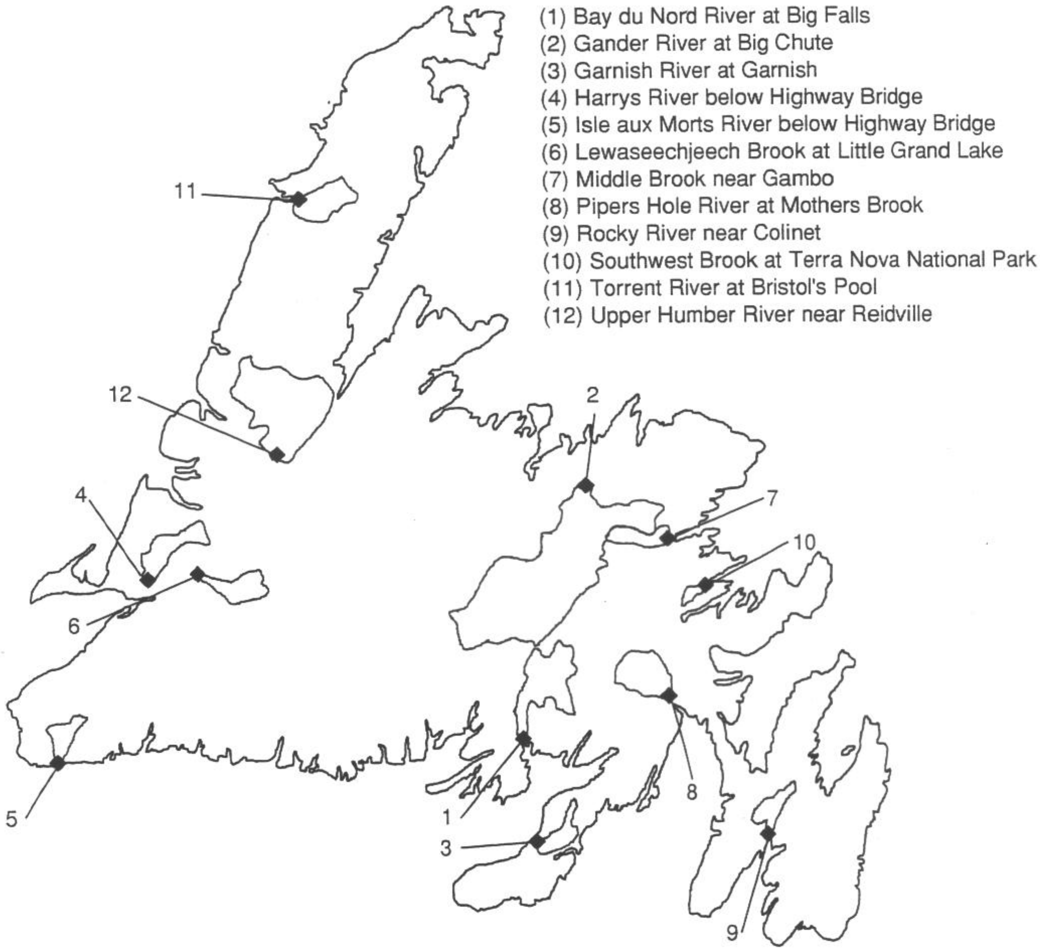


Figure 2.1
Hydroelectric Plants and Drainage Areas
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres



SGE Acres

Figure 2.2
EC Hydrometric Stations
Island Hydrology Review
Newfoundland and Labrador Hydro

Figure 2.3
EC Climate Stations
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

3 Data Analysis Techniques

As described in Section 2, the technologies and methodologies used to develop the reference inflow sequences follow accepted procedures, although there may be some questions with data derived from hydrometric stations before 1950. The purpose of the data assessment is to determine whether there are any trends or anomalies in the sequences, such as continuously increasing or decreasing trends, or step trends due to some external factor. In the case of the Hydro sequences, the most likely source of a step trend is the change in methodology for determining inflows after a station came on line, since there has been no change in EC methodology.

If a line is fitted to any time series plot it will almost always show some apparent trend; the chances of a perfectly horizontal line are slim. It is therefore important to carry out the appropriate statistical tests to assess the significance of an apparent trend. In recent years, because of the interest in climate change, there have been advances in the methods of detecting trends. This study uses the most recent accepted techniques, as well as standard hydrological plotting methods.

In statistical terms, the purpose of trend analysis is to determine if a series of observations of a random variable is generally increasing or decreasing with time, or whether the probability distribution has changed with time (Helsel and Hirsch, 1992). Two types of trends may be distinguished: step trends, and monotonic trends. Step trend tests are for testing changes before and after a known event such as a change in measurement techniques, forest fire, construction of a dam, or diversion. A monotonic trend is one that is continuously increasing or decreasing with time. Monotonic trend tests are used where there is an unbroken or nearly unbroken long record and there has been no known intervention of the record. This type of test is often used to look for effects of climate change. Both types of trend test were used in this study.

The methods used in the study for assessment of the data series are described below; Section 4 provides the results. A combination of various graphical and formal statistical approaches are used.

3.1 Time Series Plots and Normality Test

The time series plots show the annual average flow (expressed as a depth of runoff) over time. The data are plotted in chronological order and then smoothed using an efficient smoothing algorithm. A robust smoothing algorithm developed by Cleveland (1979) called Locally Weighted Regression Scatterplot Smoothing (LOWESS) is used in this study. LOWESS has been used by Burn and Elnur (2002) among others in the study of long term trends. Smoothing the data allows trends or runs of dry and wet periods (if any) to be clearly seen. This graphical approach is important because there is no statistical non-monotonic trend test available, for example, to test for cyclical trends.

Each data series was subjected to formal and graphical tests for normality. This test is essential to ensure that any parametric statistical tests used, such as regression, two-sample t-tests, or autocorrelation tests, are valid. The probability plot correlation coefficient (PPCC) or Ryan-Joiner test for normality is used here.

3.2 Monotonic Trend Analysis

This is the primary test for the assessment of long term trends. It is assumed that there is a monotonic (a constantly increasing or decreasing slope) trend. The most popular test for monotonic trend is the Mann-Kendall non-parametric test for trend. This test was first used by Mann (1945) and Kendall (1975) subsequently derived the distribution of the test statistic. In this study, the distribution of the test statistic is generated by a computer intensive permutation approach as in Burn and Elnur (2002). The details of the test are documented in Helsel and Hirsh (1992) and in Burn and Elnur (2002). This test has been found to be an excellent tool for detecting trend by various researchers.

An apparent monotonic trend may in fact be caused by a step trend (see below) or by autocorrelation, in which case the computed test statistic is not valid. A series that is significantly autocorrelated will tend to inflate the magnitude of monotonic trends. In certain cases, it may be necessary to remove the autocorrelations (by prewhitening) before carrying out any test for trends. However, a recent study by Fleming and Clarke (2002) shows that prewhitening the series reduces the statistical power of the trend test. Also, it is not possible to tell whether the autocorrelation was the cause of the apparent trend or vice versa. Therefore in this study, no prewhitening was used before carrying out the trend test. The effect of not prewhitening is that the results will be conservative, that is, the test is more likely to show that a trend is significant.

A special case of the monotonic trend is a linear trend. This case can be checked by a regression of the data with time as an explanatory variable. This is appropriate only if the assumptions of regression are valid.

3.3 Step Trend Analysis

If there is a known intervention at a certain point in the time series, a step trend test (Helsel and Hirsh, 1992) will provide a check to see if the distribution of the data before the intervention is the same as that after the intervention. Intervention in a hydrologic time series can take various forms such as a change in streamflow measurement technique, an extensive forest fire or clear-cutting. The two-sample t-test is used here. The data series is split into two parts at the time of the intervention and the means and variances of the two series are then compared. A statistically significant result will indicate a step trend.

A step trend can also be seen in the boxplots of the before and after series, and in plotted mass curves (see Section 3.6), and more formally from the F-test or the nonparametric Levene's test for equality of variances. A graphical approach based on overlaying the normal probability plot of the before and after data is also used to check for the similarity of the before and after probability distributions. If the distributions are similar, the confidence intervals should overlap substantially (more than 25 percent) (Van Belle, 2002). Otherwise it shows that the before and after series may have significantly different distributions.

3.4 Runs Analysis

A run is a series of consecutive values above or below the median, and the run length is a count of the values either above or below. Runs analysis (Gibbons, 1986) is a time series analysis tool that indicates whether there are unusually large or small numbers of runs, and whether any of them lasted an unusual length of time.

The distribution of run lengths also provides an indication of the volatility of the series; if there are frequent changes in runs above and below the mean or median then the series is considered volatile. Too many or too few runs indicate that there may be a problem with randomness of the data. A normal pattern for hydrological time series is one of randomness. The first of the two tests available for randomness is based on the number of runs above and below the median. The second test is based on the number of runs up or down (increasing or decreasing). The expected value is calculated assuming the series is random. The following table illustrates what these two tests indicate.

Test for Randomness	Condition	Indicates
Number of runs about the median	More runs observed than expected Fewer runs observed than expected	Mixed data from two populations Localized clustering of data
Number of runs up and down	More runs observed than expected Fewer runs observed than expected	Oscillation – data varies up and down rapidly Localized trending of data

With both tests, the null hypothesis is that the data is a random sequence. The test statistic for both tests is approximately standard normal, and uses the normal distribution to obtain p-values. P-values less than 0.05 indicate statistical significance. It must be pointed out however that the runs tests only indicate localized trends and not long term trends.

3.5 Mass Curve Analysis

Mass curve analysis is a standard hydrological plotting technique that can be used to detect the subtle changes in the homogeneity or consistency of a set of data. The technique is non-statistical, and is well-documented in most hydrological texts. Both single and double mass curves were used in this study.

A single mass curve is a plot of the cumulative flows against time. A record that is homogeneous and consistent will plot as a straight line. Any change in the consistency or homogeneity of the data record will show up as a change in the slope of the mass curve. Hence major changes such as in measurement techniques or location of gauges would be seen as breaks or changes in slopes of the mass curve if they have affected the data.

A double mass curve is a plot of the cumulative flows against the cumulative flows of another station that is known to be consistent. Sometimes the average of several stations can be used as a basis of comparison. Again, a change in slope indicates that the data set is internally inconsistent.

4 Data Analysis

4.1 Data Series Tested

The three types of data series described in Section 2 were analyzed using the data assessment techniques outlined in Section 3. The three types of data are

- Hydro's reference inflow sequences from seven basins;
- Long term natural streamflow data from EC hydrometric stations;
- Long term annual total precipitation series from nine EC meteorological stations.

The summary statistics for each series are given in Appendix E.

4.2 Analysis

The results of the analysis using each of the techniques described in Section 3 are presented below.

The procedure was to check the plots and test for normality before proceeding to look for monotonic or step trends. The trend tests are both statistical and graphical, and can be used to detect anomalies as well as trends due to such factors as changes in land uses in a basin or climate change.

4.2.1 Time Series Plots and Normality Tests

Time series plots with LOWESS lines for each type of series are shown in Figures 4.1 to 4.5. The LOWESS line is of most interest in these plots, rather than the individual data points. Individual time series plots for each of the natural and Hydro series are shown in Appendix F.

Figure 4.1 shows the plots for the EC natural flow stations with records extending back before the mid-1950s, and Figure 4.2 shows the plots for the stations established after the mid-1950s. Most of the natural rivers do not show any monotonic trend, with a few exceptions. Lewaseechjeech Brook shows an upward trend, possibly resulting at least in part from a six year data gap from 1967 to 1972. There was also a change in gauge location due to the paper company's activities. Upper Humber River shows a downward trend in the early part of the series; Torrent River shows a downward trend in more recent years.

Figure 4.3 shows the plots for the precipitation series. One would expect them to be similar to the streamflow plots, but several of the nine smoothed lines show upward trends. If there is an increasing trend in precipitation it could be expected to show up in the streamflow series as well, but this does not appear to be the case. One possible explanation could be that temperature is increasing, thus resulting in more evapotranspiration counteracting the additional precipitation. Another possible explanation could be local effects, due to the fact that the precipitation stations are located in populated areas, and may not reflect conditions in the streamflow basins. A third possibility is that there are problems with the precipitation data sets. A detailed study would be required to investigate these possibilities.

Figures 4.4 and 4.5 show the plots for the Hydro series. Figure 4.4 is based on the total length of Hydro's sequences, and Figure 4.5 is based on the last 30 years, since this is the period the Board has instructed Hydro to use pending the results of this study. The smoothed LOWESS lines show a downward trend at Cat Arm when all the data are used. This is consistent with the downward trend of Upper Humber, from which the sequence for the early years was derived. When only data from 1950 onwards are used, a mild upward trend can be seen.

As Figure 4.4 shows, the trend for the Hinds Lake series is downward in the early years, then slightly upward in the last part of the series. The smoothed LOWESS lines for Victoria and Grey Rivers appear to have upward trends for the period 1972 to 2001. No other Hydro basins show monotonic trends.

Observations from the time series plots are summarized in Tables 4.1 and 4.2, in the column labeled "Trend Plot", and also in the last column, labeled "Remarks".

The series were tested for normality before the statistical tests were carried out. The results were that the null hypothesis that the data series were normally distributed cannot be rejected at the 5 percent level for all the series tested. This result means that parametric methods which assume normality, such as the two-sample t-test, can be used for step trend and linear trend test analysis. It also means that the median and the mean values of the series can be expected to be close.

4.2.2 Monotonic Trend Test

The Mann-Kendall test for monotonic trend was carried out for all the series assuming that a trend exists. The results of the test are shown in Table 4.1 for the precipitation and streamflow series, and in Table 4.2 for the Hydro series. The Mann-Kendall test statistic is S, and Z is the calculated test statistic for significance based on the normal approximation. The p-values are obtained using the permutation method, and Sen's slope β is a robust estimate of the slope of the trend. A linear trend test using a simple regression with time as an explanatory variable was also computed, and these results are also shown in Tables 4.1 and 4.2.

Values less than 0.05 in the p-value columns indicate significant trend. Sen's slope is dimensional, having values of mm/y, and indicates how much the runoff or precipitation is increasing or decreasing. A Sen's slope value of +5, for example, would mean that the runoff or precipitation is increasing by +5 mm/y.

Following the classification of Burn (1997), the trends were classified into five categories based on the direction of the trend and the p-value from the Mann-Kendall test:

- Category 1 is a statistically significant increasing trend (SI) with p-values less than 0.05.
- Category 2 is a mild increasing trend (MI) with p-values between 0.05 and 0.10.
- Category 3 is a weak trend or no trend. P-values are greater than 0.10.
- Category 4 is a mild decreasing trend (MD) with p-values between 0.05 and 0.10.
- Category 5 is a statistically significant decreasing trend (SD) with p-values less than 0.05.

Most of the natural flow series are in Category 3; the exceptions are Lewaseechjeech Brook in Category 1, Torrent River in Category 5 and Garnish River is in Category 2. Five of the nine precipitation series are in Category 1, the others are in Category 3. As mentioned above, this result is unusual as the increasing trend in the precipitation is not also seen the streamflow series. Due to possible problems with the data sets, and the fact that the focus of this report is streamflow, not precipitation, the precipitation series were not analyzed any further.

Each Hydro series was checked for three different periods, the whole period of record, the period 1950 to 2001 (if different from the whole period), and the period 1972 to 2001 (the last 30 years). Hinds Lake has the longest reliable record; it shows no trend for the whole period, a statistically significant upward trend for the 1950-2001 period, and no trend for the 1972 to 2001 period. Cat Arm is similar, except that the trend is significantly down for the whole period, mildly up for the middle period is (Category 2 rather than Category 1), and flat (no trend) in the last period. As discussed in Section 2, the quality of the source data may not be as good for the Cat Arm record before 1950 as for Hinds Lake, and there were several changes in methodology in developing the early part of the Cat Arm record.

Of the Bay d'Espoir basins, Victoria and Grey Rivers are in Category 1 for the period 1950-2001, but Upper and Lower Salmon show no significant trend over this period. For the period 1972 to 2001, only Lower Salmon shows a significant upward trend. The diversions of the Victoria and Grey River were completed by 1971; the possibility that the apparent monotonic trend in these basins is actually a step trend relating to a change in methodology was explored using step trend test and mass curves as discussed below.

The Paradise River series starts in 1953. There is no trend in either the 1953 to 2001 period or the 1972 to 2001 series. This result is not unexpected since most of the series was developed from the Pipers Hole record, which showed no trend.

The regression results generally agree with the Mann-Kendall test results with a slight difference in the p-values only.

4.2.3 Step Trend Analysis

Step trend analysis was carried out on the Hydro series to compare inflow data before development and after development. The date of the intervention (construction of the power stations or diversions) is known, and the series before and after the intervention should have statistically similar characteristics. The before/after year used is the year in which the hydro plant came into operation, when there would have been a change in flow calculation methodology. In the case of the Victoria and Grey series, the change occurred when the diversions were constructed; 1971 was chosen since it was the year in which they were completed.

In the case of Lower Salmon (Bay d'Espoir), the first unit came into service in May, 1967, and the last of the first group of six in April, 1970. For the purposes of the step trend test 1969 was chosen, the year in which four of the six units were in service. (A seventh unit was installed in 1977.) The flow calculation methodology would have been changing throughout the period of construction of the project, from 1966 until the diversions were completed in 1971.

For Cat Arm, in addition to testing for a step trend when the plant came into service in 1985, 1959 was also tested as a before/after year. In that year the flow calculation methodology changed, as described in Section 2. EC's Torrent River streamflow gauging station came into operation in 1959, and the measured flows from Torrent River were used along with Upper Humber to develop the reference inflow sequence until a station was established on the Cat Arm River itself. No significant step trend was found.

Not only should the means and standard deviations of the before and after series be similar, but the probability distributions should overlap as well. Since all the flow data are normally distributed, parametric procedures such as the two-sample t-test were used to compare the means of the before and after intervention data. The variances and distributions were also compared. A two-tail test was used because the step trend may be positive or negative. A significance level of 5 percent was used. The boxplots of the data, the t-tests results, and the probability plots are given in Appendix G.

The streamflow series from a nearby natural flow gauged river was also tested for a step trend in the same year as each of the Hydro series to see if the same step trend also occurred in the natural rivers. The results of the two-sample t-tests are summarized in Table 4.3.

Table 4.3 shows that there was a statistically significant change in the mean for the Victoria and Grey inflow series after 1971, the year White Bear and Grey River diversions were completed. This change is not seen in Gander River for the same time periods. The step trend also explains the apparent monotonic trend that was seen in the Mann-Kendall test for Victoria and Grey inflow series. The box plots and the non-overlapping probability plots in Appendix G clearly show this difference.

None of the other Hydro series shows a step trend. For Cat Arm, while there is no statistical change in the mean flows, there is a statistically significant change in the variance of the post-1985 data. The post-1985 data have smaller variance. The non-overlapping probability plots as well as the plot of the test for equal variances in Appendix G show the difference.

It is interesting to note that while there is no step trend in other Hydro series and most of the natural flow series, a step trend was seen on the Upper Humber River for the before 1985 and after 1985 periods. A step trend was also seen in the Lewaseechjeech Brook for the before 1980 and after 1980 periods; it may contribute to the monotonic trend. There is no obvious explanation for these step trends in the natural series.

4.2.4 Runs Analysis

An analysis of the number, direction and length of runs in a series is a simple and effective way to assess the volatility or predictability of a series. Each data point is plotted, and a line representing the median is drawn through the data points. The run chart for each series is given in Appendix H. Table 4.4 summarizes the results of the runs tests for both the natural and Hydro series.

Figure 4.6 provides an example of the analysis for Pipers Hole River, one of the natural gauged rivers, and for Hydro's Cat Arm series. The fundamental assumption is that the data are a random series, and as such will plot above or below the line unpredictably, including some clustering and short term trends. The Pipers Hole series provided in Figure 4.6, as an example, shows that there are 19 runs above or below the median. A run lasts until the next data point is on the other side of the median line. The expected number of runs in a completely random series of 49 observations is 25, and the p-value indicates that 19 is significantly fewer than expected, that is, there is significant clustering. The total number of runs going up and down is 26; this is also significantly fewer than expected.

The Cat Arm series shown in Figure 4.6 also has significant clustering (fewer runs than expected) but in all other ways it shows the characteristics of a random series.

Most of the natural and Hydro series passed the runs tests for randomness. Only four of the twelve natural series show some form of non-randomness. Like Pipers Hole, Lewaseechjeech Brook and Middle Brook natural flow series show significant clustering as there are statistically significant fewer runs above and below the median than are expected from a random series. The Upper Humber River series on the other hand shows the reverse, called localized trends, that is, statistically significantly fewer number of consecutive runs up or down than are expected from a random series. The longest continuously increasing/decreasing run up or down is only three, in a record length of 62 years.

Like Pipers Hole, the records for Garnish and Middle Brook Rivers also show significantly fewer consecutive runs up or down than expected, and shorter runs continuously up or down.

For the Hydro series, Grey as well as Cat Arm shows significant clustering. Upper Salmon and Paradise Rivers show significant localized trends. In the case of Paradise River, it is the same effect as at Pipers Hole, since the Paradise River series was derived from the Pipers Hole record.

Table 4.4 also shows that the runs above or below the median can be as long as 10 years, as in Cat Arm, and the longest continuous run up or down can be as long as five to six years, as in Garnish, Pipers Hole, Paradise, and Rocky Rivers. However, this does not imply that there is a long term trend. The importance of the runs analysis is that it shows that collectively, both the natural and flow series generally exhibit random behavior. The plots as well as the statistical analysis show that the series can be in fact quite volatile, rapidly changing from a downward trend to an upward trend with no predictable frequency.

4.2.5 Mass Curve Analysis

Both single and double mass curves were prepared for data from EC's natural streamflow records and for the Hydro series. Double mass curves in particular can demonstrate inconsistencies in a series. In these curves, values from the record being tested are plotted against a record from a series known to be reliable. If the slope changes, there is a good chance that it corresponds to some physical or methodological change.

Figure 4.7 shows the single mass curves for the EC natural gauged rivers plotted for the period since 1950. They all appear reasonable, that is, each individual series has basically the same slope throughout the period. The slopes of the mass curves simply indicate relative wetness or dryness. Isle aux Morts, for example, is one of the wettest basins. The apparent waviness is caused by annual flow variations.

The double mass curves in Figure 4.8 show the cumulative flows of the EC natural gauged rivers plotted using Gander River as a reference. This plot shows that Gander River provides a good reference for the other stations, even geographically remote basins like Torrent River, Rocky River and Isle aux Morts. Adjacent rivers like Middle Brook plot as straight lines, whereas the more remote ones show a bit more annual variation, but overall the slopes are consistent. A slightly wetter year or two in one basin appears to be compensated for by a relatively drier year or two following.

Gander River was therefore also used as the reference station in preparing the double mass curves for the Hydro series. Figures 4.9 to 4.11 show the double mass curves for the Bay d'Espoir basins.

All the Bay d'Espoir basins (Grey, Victoria, Upper Salmon, Lower Salmon) show some internal inconsistencies in the mass curves. In the Grey and Victoria basins, it is a break in slope, while in the others it is an offset. In the cases of Grey and Victoria this result corroborates the step trend tests. It appears that the Grey and Victoria inflows are underestimated prior to 1971.

In the cases of the Upper and Lower Salmon Basins, the coincidental offsets in the mass curves suggest the change in method of flow estimate for the outflow from each of these sub-catchments resulted in a re-allocation of the total run-off from the two sub-basins. When the total volume is computed from all the four inflow sequences, the sequence appears to be internally consistent, as Figure 4.11 shows. This result suggests that it is the distribution of the flows among the four major basins that requires rectification and that the underestimate of the Grey and Victoria flows prior to 1971 is at least partly compensated for by Upper and Lower Salmon over-estimates for that period. Resolution of these indicated inconsistencies will require careful review of the historical records to re-allocate the total basin outflow amongst the four sub-basins.

Figure 4.12 shows the double mass curve for Hinds Lake; there appears to be a break point in 1964. There is a period from 1957 to the early 1960's when changes occurred in the natural flow series from which the Hydro record was developed. In 1957 EC established a flow measuring station on Hinds Brook so the method of deriving the inflows changed; also, flows in the early 1960's were unusually low, which could affect the interpretation of the point of the change in slope of the mass curve. Because flows were low, the paper company operating in the area opened up the outlet of the lake by blasting to release additional water, possibly confusing the record further.

The single mass curve rather than the double mass curve is shown for the Cat Arm series in Figure 4.12, since Gander River data do not extend back before 1950. There appears to be some internal inconsistency in the first part of the record. After 1959, data were available from the Torrent River hydrometric station for estimating flows, so the additional information from this river appears to have improved the estimates for Cat Arm. Prior to that time, the flows were synthesized from the Upper Humber station only. The step trend test, however, showed no significant difference in the series for a before/after year of 1959.

Two mass curves for Paradise River are provided in Figure 4.13. One uses Gander River as the reference series, the other uses the Pipers Hole series. Both show a break point around 1989, when the plant came into service. The step trend test does not show a significant difference, probably because of the few data points after 1989. The difference is confirmed by Hydro's experience; the station has not produced as much energy as the inflow sequence would have suggested, even in wet years.

4.2.6 Data Assessment

From the results of the analysis presented above, the evidence for monotonic or step trends is inconsistent. Some of the precipitation series show upward trends, but these are not reflected in the streamflow series. The lack of trend in streamflow series agrees with the findings of other recent research. Only the Lewaseechjeech series shows a trend, and its record was not included by EC in the RHBN, perhaps because of missing years in the early part of the record.

The Hydro series show no convincing evidence of any long term trends. In the cases of Hinds Lake and Cat Arm, which have the longest records, the period chosen for evaluation affects whether or not there is an apparent trend, and its direction. Some apparent trends in the Victoria and Grey Rivers can be attributed to a change in the methodology of constructing flow sequences around 1971, confirmed by step trend test and mass curves analysis of these series. The basic data used to develop the Bay d'Espoir sequences appears to be sound, but the distribution of flows among the basins requires reevaluation. This is discussed further in Section 8.

The analysis of runs showed that some of the rivers exhibited clustering and localized trending. However, this does not imply that there is any long term trend. The series are in fact quite random and stationary and as the runs plots show, any attempt to perform medium or long term forecasting (that is, for the next year or the next few years) would be futile.

Table 4.1
Summary of Trend Analysis - No Prewhitening

Name of Series	Years	n	Trend plot	Mann-Kendall				Linear Regression			Category	Remarks
				S	Z	p-value1	Sen's β	Reg b_1	R^2	p-value2		
River Flow Series (12)												
Bay du Nord River	1952-2001	49	slight upw then dw	-28	-0.246	0.806	-0.220	0.525	0.2	0.760	3	practically horizontal
Lewaseechjeech Brook	1956-2001	39	upw, mono	202	2.512	0.012	5.481	5.094	16.4	0.011	1	
Upper Humber River	1930-2001	62	dw then mild upw	-245	-1.465	0.143	-2.083	-2.193	6.0	0.054	3-	early years show dw trend
Gander River at BC	1950-2001	52	mild upw	140	1.113	0.266	1.428	1.985	4.7	0.127	3+	
Rocky River	1950-2001	52	almost horiz	-10	-0.066	0.947	0.000	0.414	0.1	0.796	3	practically horizontal
Pipers Hole River	1953-2001	49	mild upw	121	1.019	0.308	1.440	1.989	2.7	0.259	3+	
Garnish River	1959-2001	43	slight upw	171	1.780	0.075	4.600	2.078	11.8	0.024	2	later years dw
Harrys River	1969-2001	33	upw, dw, slight upw	4	0.043	0.966	0.492	0.496	0.1	0.891	3	practically horizontal
Middle Brook	1960-2001	42	dw then almost hor	-83	-0.870	0.385	-1.370	-1.276	1.4	0.451	3-	
South West River	1968-2001	34	very slight dw	-59	-0.854	0.393	-2.833	-2.568	2.9	0.333	3-	
Isle Aux Morts River	1963-2001	39	horiz then upw	21	0.256	0.800	1.455	1.148	0.2	0.802	3	horiz wavy
Torrent River	1960-2001	42	upw then gradual dw	-225	-2.498	0.013	-4.906	-5	11.1	0.031	5	dw from 1980
Upper Humber (1953-2000)	1953-2001	49	mild upw	124	1.085	0.278	1.677	1.863	2.7	0.264	3+	no data from 48-52
Precipitation Series (9)												
Colinet	1939-1991	37	slight dw then horiz	-53	-0.705	0.480	-1.154	-1.060	1.0	0.550	3-	
St. John's Airport	1942-1999	56	slight dw then dw	8	0.053	0.960	0.073	-0.489	0.1	0.780	3	practically horizontal
Gander	1934-1999	63	upw, mono	767	4.540	0.000	4.315	4.521	28.3	0.000	1	One outlier (1962, 1632.4)
Corner Brook	1934-1999	58	dw to 1960 then upw	472	3.290	0.001	3.327	2.983	15.3	0.002	1	from 1960 upw mono
Daniels Harbour	1949-1994	30	upw then dw	65	1.165	0.250	4.538	2.240	2.1	0.450	3+	
Deer Lake	1934-1999	44	upw, mono	378	3.720	0.000	5.609	5.420	36.7	0.000	1	
Exploits	1957-1999	38	wavy horiz	3	0.026	0.979	0.045	-0.041	0.0	0.980	3	practically horizontal
Grandfalls	1939-1999	40	upw, mono	228	2.632	0.008	4.437	3.848	15.5	0.012	1	
Port Aux Basques	1910-29, 56-96	54	dw then upw 50's on	323	2.420	0.016	2.216	1.736	8.4	0.033	1	long break in series
Port Aux Basques (1956-96)	1956-1996	34	upw, mono	189	2.840	0.005	8.342	8.129	27.0	0.002	1	dw from 1910-1929

All data sets are normally distributed with p-values > 0.1 using the Anderson-Darling test.

Categories: 1 = SI ($p<0.05$), 2 = MI ($0.05 <p<0.10$), 3 = Weak or No trend, 4 = MD ($0.05 <p<0.10$), 5 = SD ($p < 0.05$)
The Mann-Kendall test uses resampling

Table 4.2

Summary of Trend Analysis - No Prewhitening: Hydro Series

me of Seri	Years	n	Trend plot	Mann-Kendall				Line
				S	Z	p-value1	Sen's β	Reg b_1
Hydro Series (7)								
Hinds Lake	1927-2001	75	then slight	206	0.895	0.371	0.833	0.751
Hinds Lake	1950-2001	52	upw, mono	289	2.409	0.016	3.292	3.314
Hinds Lake	1972-2001	30	haped not m	13	0.201	0.840	0.833	1.098
Cat Arm	1930-2001	72	then mild u	-412	-1.980	0.048	-2.176	-2.646
Cat Arm	1950-2001	52	ild upw mo	225	1.787	0.074	3.275	3.285
Cat Arm	1972-2001	30	then U sha	-16	-0.253	0.800	-0.800	-2.234
Lower Saln	1950-2001	52	oriz then up	65	0.494	0.621	0.955	1.050
Lower Saln	1972-2001	30	upw mono	133	2.527	0.012	9.833	8.710
Victoria	1950-2001	52	upw mono	268	2.190	0.029	3.489	3.200
Victoria	1972-2001	30	haped not m	10	0.154	0.878	0.333	-0.976
Grey	1950-2001	52	pw then hor	336	2.594	0.010	5.053	5.490
Grey	1972-2001	30	haped not m	-38	-0.633	0.527	-3.857	-2.744
Upper Saln	1950-2001	52	slight dw	-52	-0.383	0.700	-0.848	-0.336
Upper Saln	1972-2001	30	upw then dw	43	0.746	0.455	5.500	3.065
Paradise	1953-2001	49	oriz then dw	-67	-0.543	0.587	-0.789	-0.671
Paradise	1972-2001	30	upw then dw	-25	-0.419	0.676	-0.714	-2.186

All data sets are normally distributed with p-values > 0.1 using the Anderson-Darling test.

Categories: 1 = SI (p1<0.05), 2 = MI (0.05 <p1<0.10), 3 = Weak or No trend, 4 = MD (0.05 <p1<0.10), 5

The Mann-Kendall test uses resampling

Table 4.3
Step Trend Tests (2-sample t-test, 2-tailed): Comparisons with Natural Flowing Rivers Nearby

River	Before/After	n_1, n_2	p-value	Remarks
Victoria River	1971	22, 30	0.019	After is higher
Grey River	1971	22, 30	0.000	After is higher
Gander River (natural)	1971	22, 30	0.411	After is higher but n.s.
Lower Salmon River	1969	19, 33	0.839	practically the same mean
Bay du Nord River (natural)	1969	17, 32	0.274	After is higher but n.s.
Upper Salmon River	1983	33, 19	0.571	After is higher but n.s.
Gander River (natural)	1983	33, 19	0.699	After is higher but n.s.
Cat Arm River	1985	55, 17	0.142	Before is higher but n.s.,variance of after is significantly smaller
Upper Humber (natural)	1985	45, 17	0.043	Before is higher
Lewaseechjeech River (natural)	1985	22, 17	0.309	After is higher but n.s.
Cat Arm River	1959	30, 42	0.122	Before is higher but n.s., variance of after is smaller but n.s.
Upper Humber (natural)	1959	20, 42	0.187	Before is higher but n.s., variance of after is smaller but n.s.
Paradise River	1989	36,13	0.192	Before is higher but n.s.
Pipers Hole River (natural)	1989	36,13	0.52	After is higher but n.s.
Hinds Lake	1980	53, 22	0.176	After is higher but n.s
Upper Humber River (natural)	1980	41, 21	0.127	Before is higher but n.s.
Lewaseechjeech River (natural)	1980	19, 20	0.041	After is higher

Before/After year = Year plant came into operation or year there is a change of methodology

Red = significant at 5% level

All assumptions of the t-test are met. Before and After data are both approximately normally distributed.

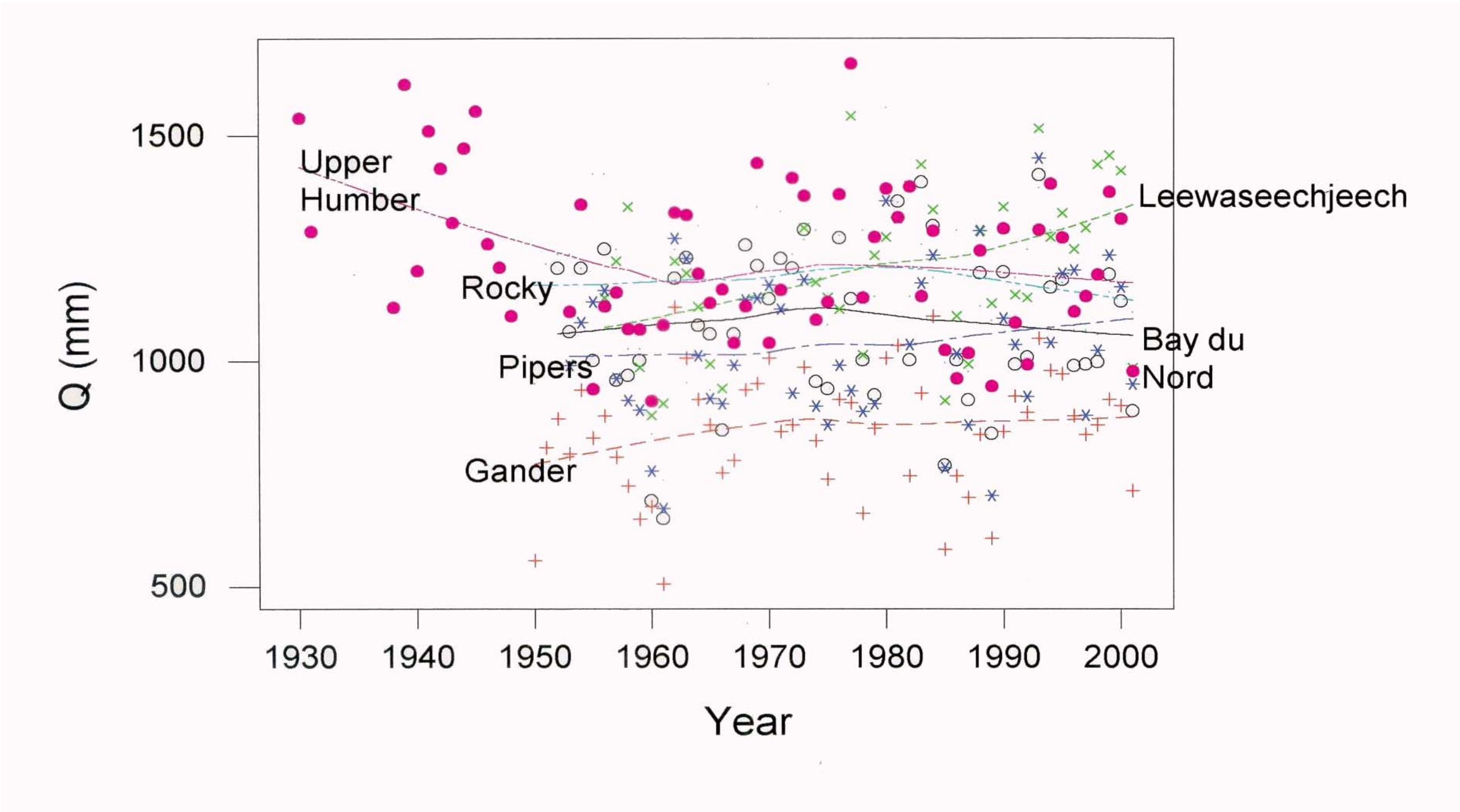
n_1 = # of years before intervention

n_2 = # of years after intervention

Table 4.4
Summary of Runs Analysis

Name of Series	Years	n	Runs above and below the median					Length of runs				
			RAB	E(RAB)	LRABM	p-value 1	p-value 2	NRUD	E(NR)	LRUD	p-value 3	p-value 4
River Flow Series (12)												
Bay du Nord River	1952-2001	49	24	25.49	6	0.334	0.667	33	32.33	3	0.591	0.409
Lewaseechjeech Brook	1956-2001	39	15	20.39	8	0.039	0.961	22	25.67	4	0.077	0.923
Upper Humber River	1930-2001	62	26	32.00	9	0.062	0.938	35	41.00	3	0.033	0.967
Gander River at BC	1950-2001	52	23	26.85	6	0.139	0.861	30	34.33	4	0.073	0.927
Rocky River	1950-2001	52	23	27.00	7	0.133	0.866	32	34.33	6	0.217	0.783
Pipers Hole River	1953-2001	49	19	25.49	6	0.030	0.970	26	32.33	5	0.014	0.986
Garnish River	1959-2001	43	21	22.49	6	0.323	0.677	21	28.33	5	0.003	0.997
Harry River	1969-2001	33	15	17.48	5	0.190	0.810	19	21.67	4	0.129	0.871
Middle Brook	1960-2001	42	15	22.00	6	0.014	0.986	21	27.67	4	0.006	0.994
South West River	1968-2001	34	16	18.00	6	0.243	0.757	22	22.33	3	0.445	0.555
Isle Aux Morts River	1963-2001	39	17	20.49	6	0.129	0.871	22	25.67	4	0.077	0.923
Torrent River	1960-2001	42	17	22.00	7	0.059	0.941	25	27.67	4	0.159	0.841
Hydro Series (7)												
Hinds Lake	1927-2001	75	36	38.49	8	0.281	0.719	47	49.67	4	0.230	0.770
Cat Arm	1930-2001	72	28	36.97	10	0.017	0.984	45	47.67	4	0.225	0.775
Lower Salmon	1950-2001	52	23	27.00	8	0.131	0.869	32	34.33	4	0.217	0.783
Victoria	1950-2001	52	23	27.00	8	0.131	0.869	30	34.33	4	0.073	0.927
Grey	1950-2001	52	17	27.00	8	0.003	0.998	34	34.33	3	0.456	0.544
Upper Salmon	1950-2001	52	23	27.00	8	0.131	0.869	27	34.33	4	0.007	0.993
Paradise	1953-2001	49	23	25.41	6	0.243	0.757	26	32.33	5	0.014	0.986
Hinds Lake	1950-2001	52	23	27.00	8	0.131	0.869	30	34.33	4	0.073	0.927
Cat Arm	1950-2001	52	23	27.00	9	0.133	0.867	32	34.33	4	0.217	0.783

All data sets are normally distributed with p-values > 0.1 using the Anderson-Darling test.
RAB = Number of runs about the median, E(RAB) = Expected number of runs, LRABM = Longest run about the median, p-value 1 = p-value for clustering
p-value 2 = p-value for mixtures, NRUD = Number of runs up and down, E(NR) = Expected number of runs, LRUD = Longest run up or down
p-value 3 = p-value for trends, p-value 4 = p-value for oscillation. Red = statistically significant at the 5% level



SGE Acres

Figure 4.1
Time Plot of Natural Flow Series with LOWESS Lines (1928 - 2001)
Island Hydrology Review
Newfoundland and Labrador Hydro

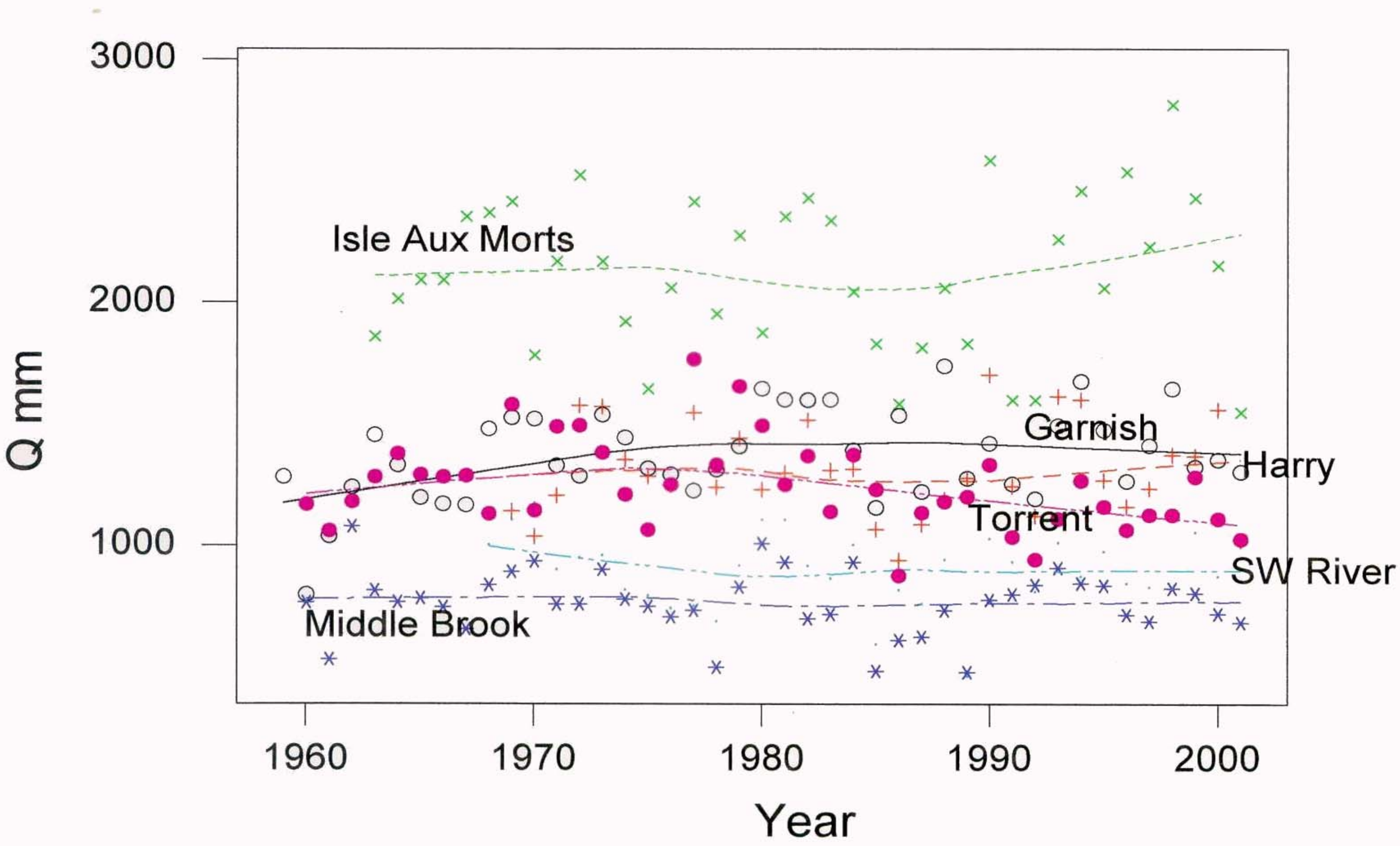


Figure 4.2
Time Plot of Natural Flow Series with LOWESS Lines (1958 - 2001)
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

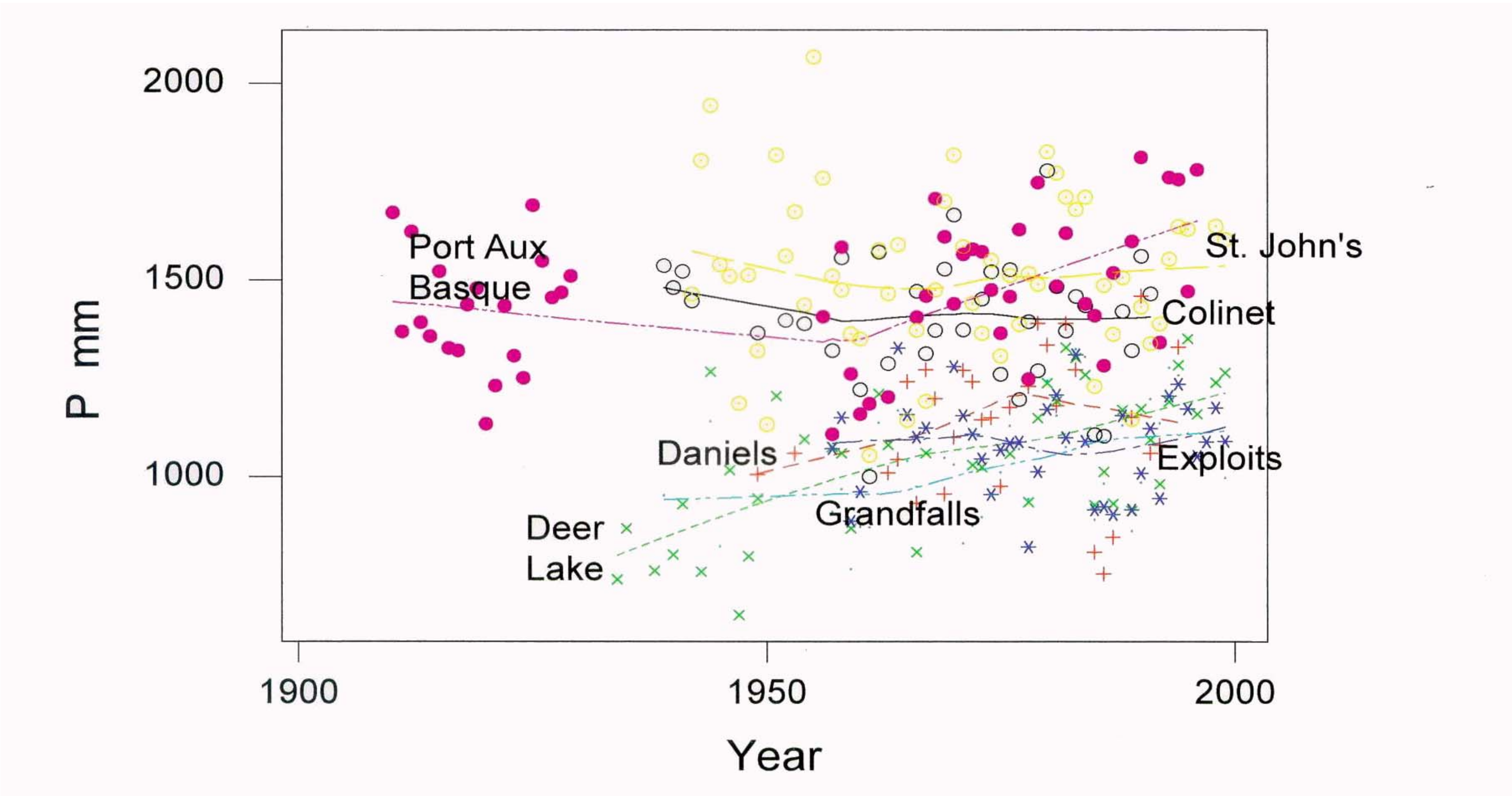


Figure 4.3
Time Plot of Precipitation Series with LOWESS Lines
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

#N/A

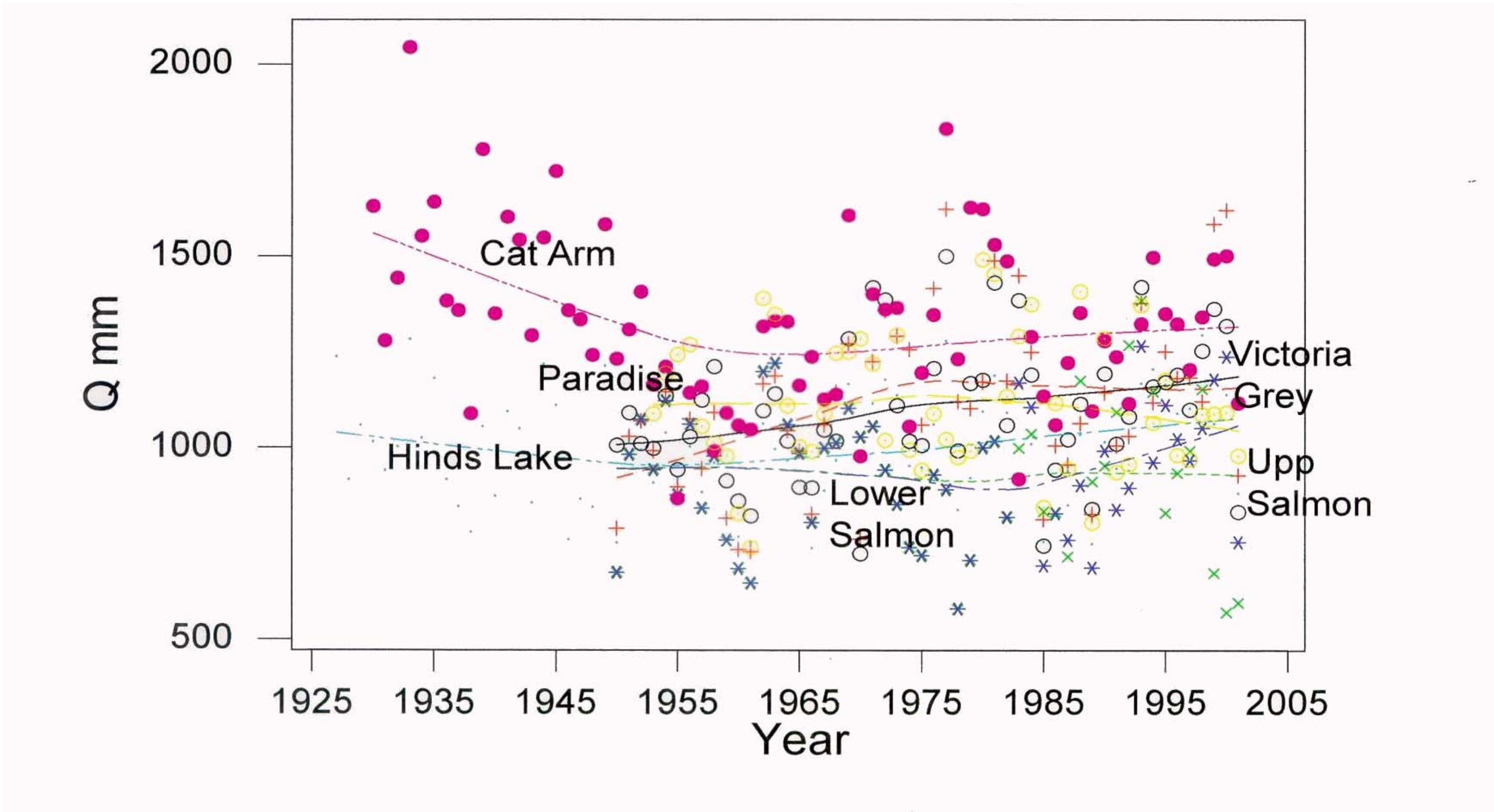


Figure 4.4

Time Plot of Hydro Series with LOWESS Lines

Island Hydrology Review

Newfoundland and Labrador Hydro

SGE Acres

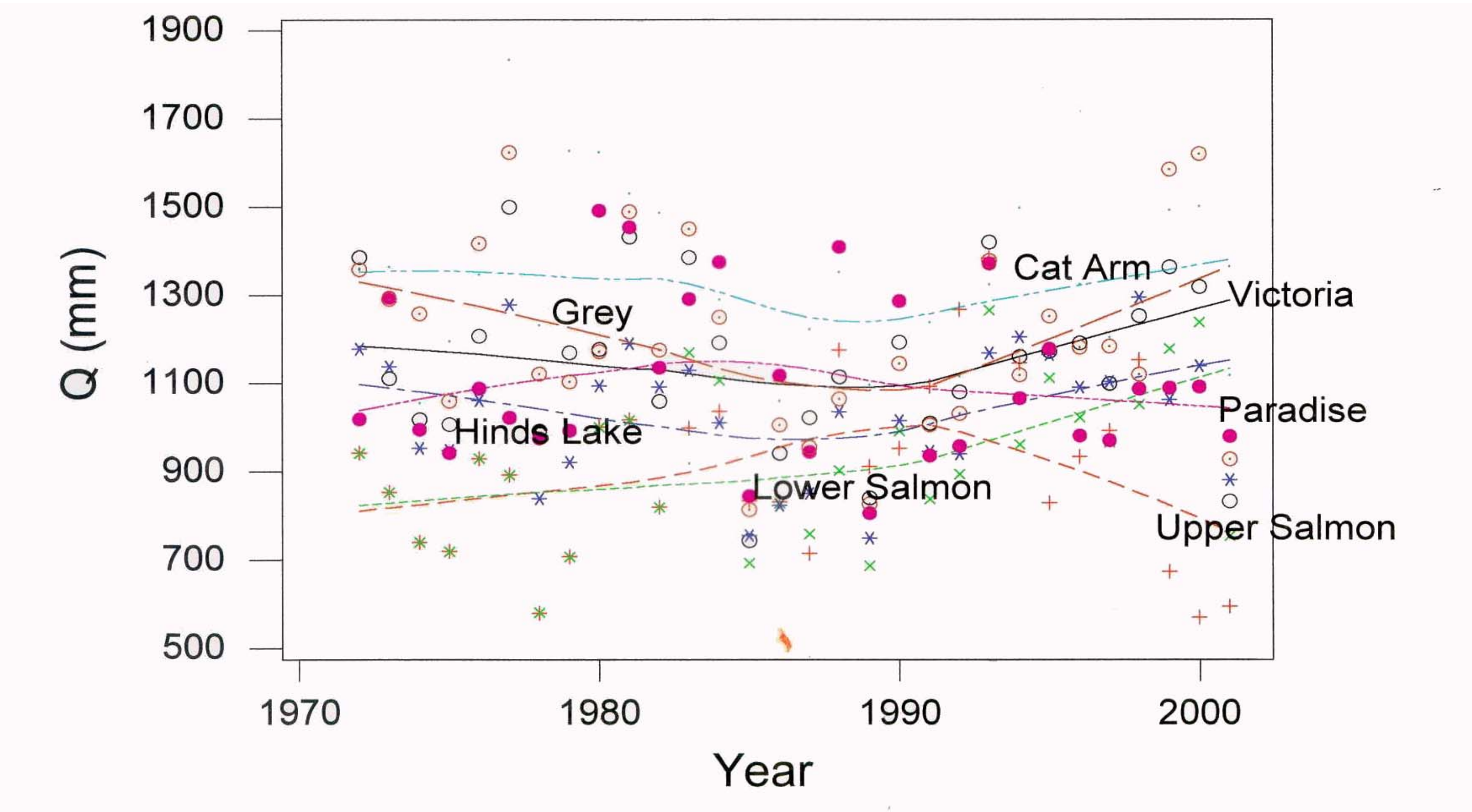
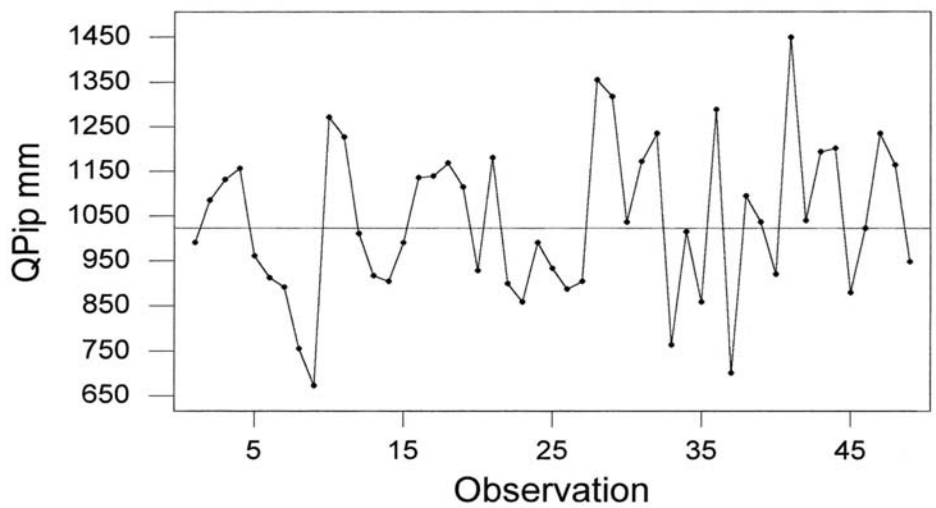


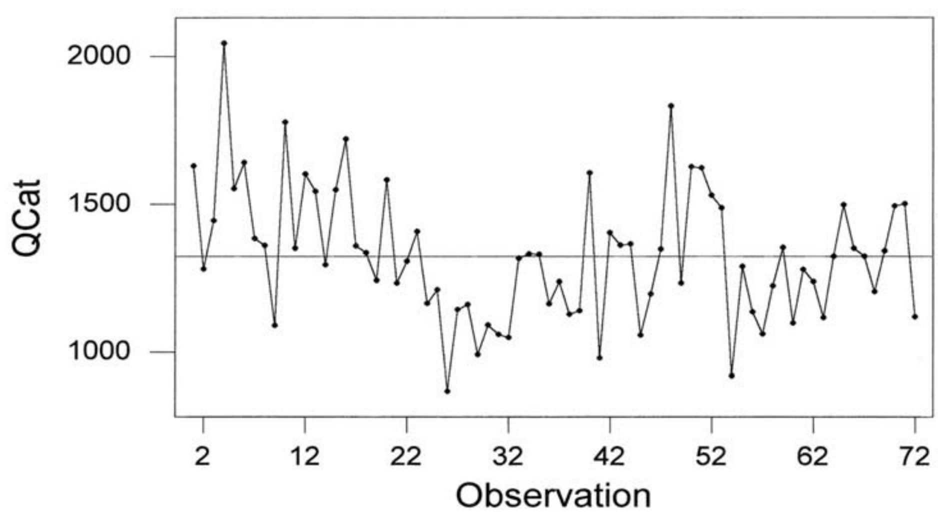
Figure 4.5
Time Plot of Hydro Series with LOWESS Lines (1972 - 2001)
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres



Piper's Hole River

Number of runs about median:	19.0000	Number of runs up or down:	26.0000
Expected number of runs:	25.4898	Expected number of runs:	32.3333
Longest run about median:	6.0000	Longest run up or down:	5.0000
Approx P-Value for Clustering:	0.0304	Approx P-Value for Trends:	0.0144
Approx P-Value for Mixtures:	0.9696	Approx P-Value for Oscillation:	0.9856



Cat Arm Hydro Series

Number of runs about median:	28.0000	Number of runs up or down:	45.0000
Expected number of runs:	36.9722	Expected number of runs:	47.6667
Longest run about median:	10.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.0165	Approx P-Value for Trends:	0.2251
Approx P-Value for Mixtures:	0.9835	Approx P-Value for Oscillation:	0.7749

Figure 4.6
Samples from Runs Analysis:
Pipers Hole River and Cat Arm Hydro Series
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

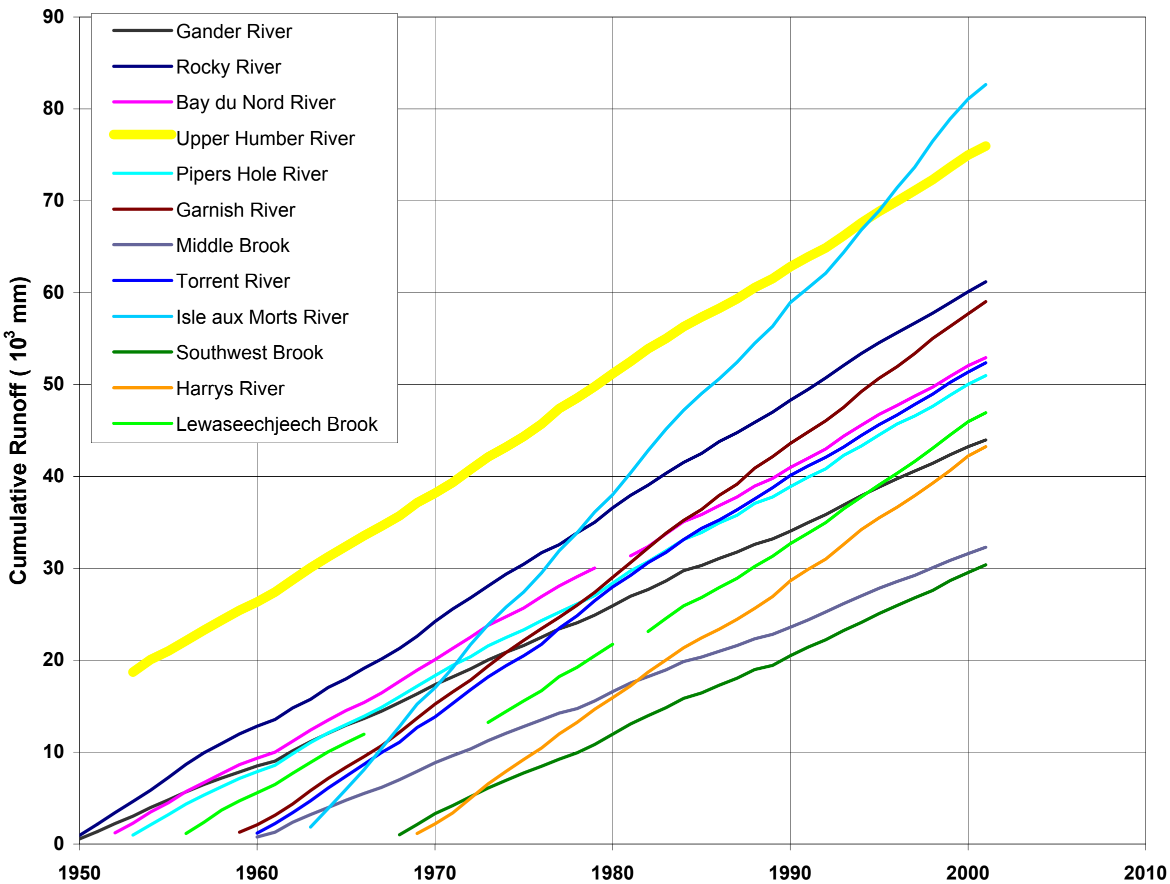


Figure 4.7
Single Mass Curves:
Natural Streamflow Series
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

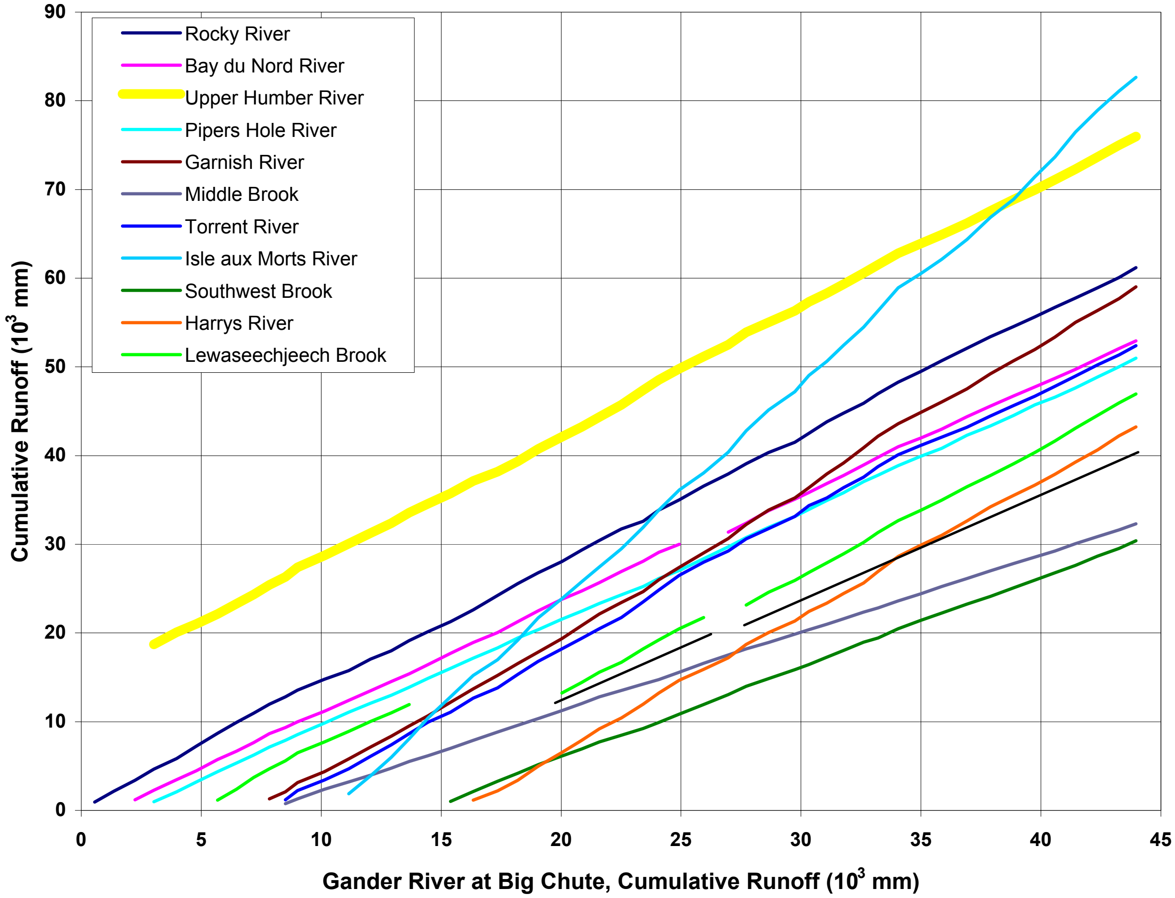


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Figure 4.8
Double Mass Curves:
Natural Streamflow Series
Island Hydrology Review
Newfoundland and Labrador Hydro

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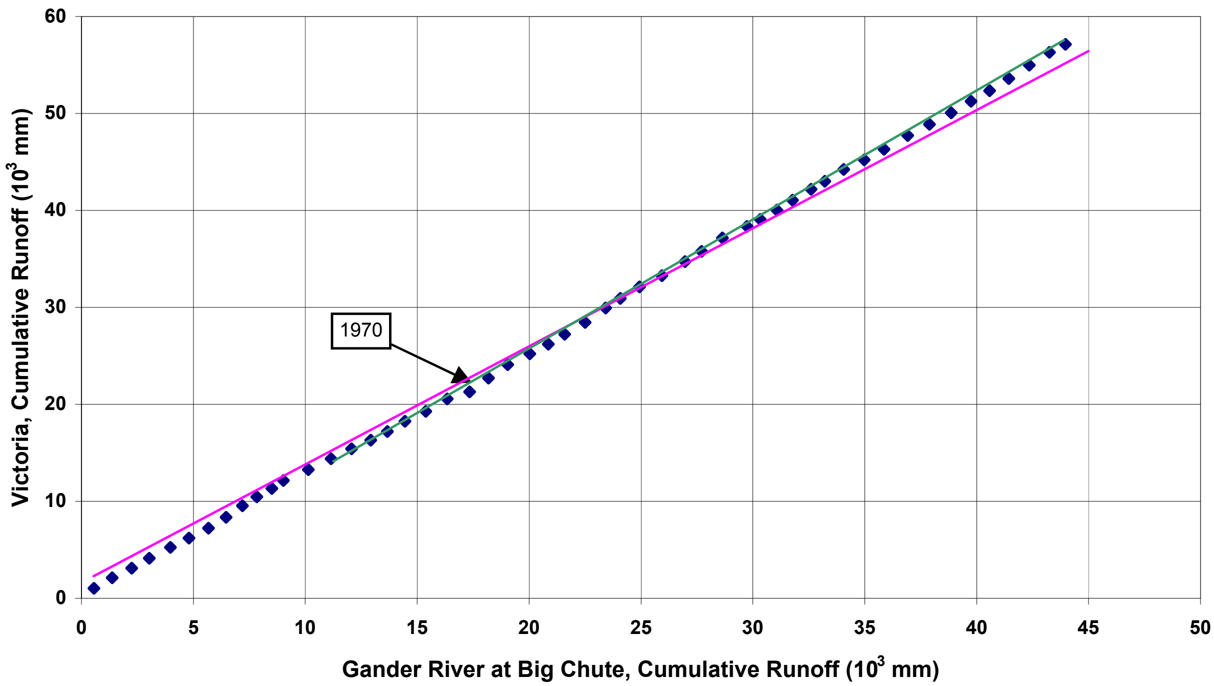

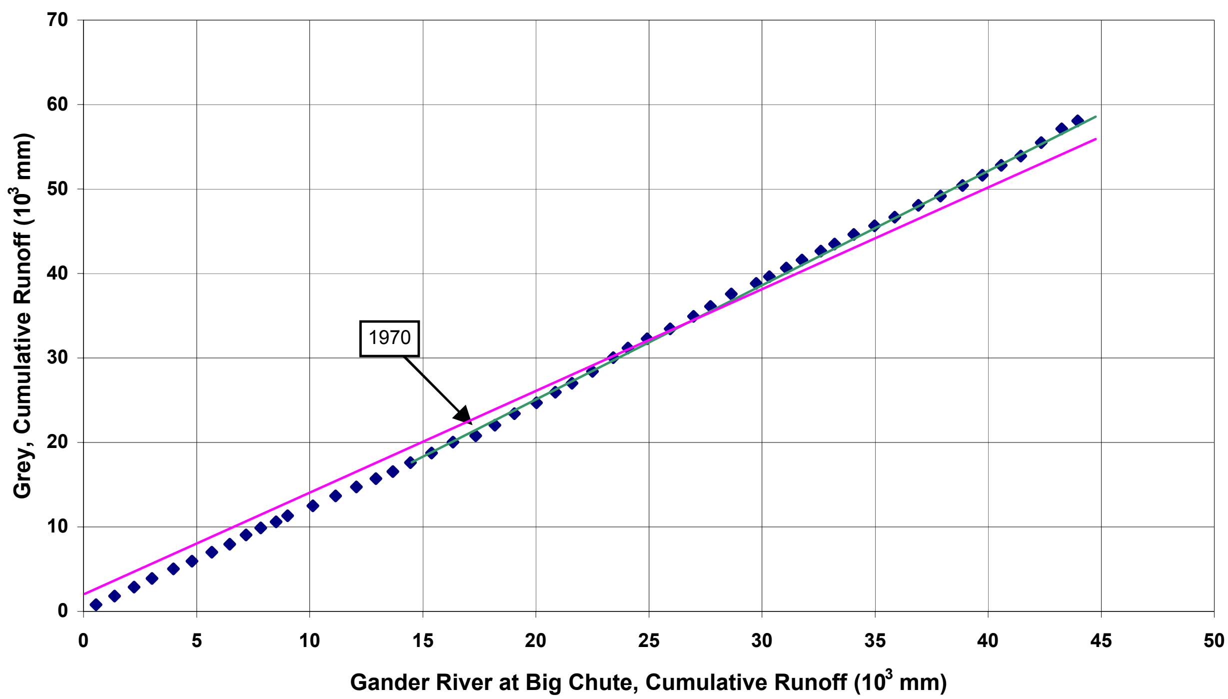

Figure 4.9
Double Mass Curves:
Victoria and Grey Inflows
Island Hydrology Review
Newfoundland and Labrador Hydro

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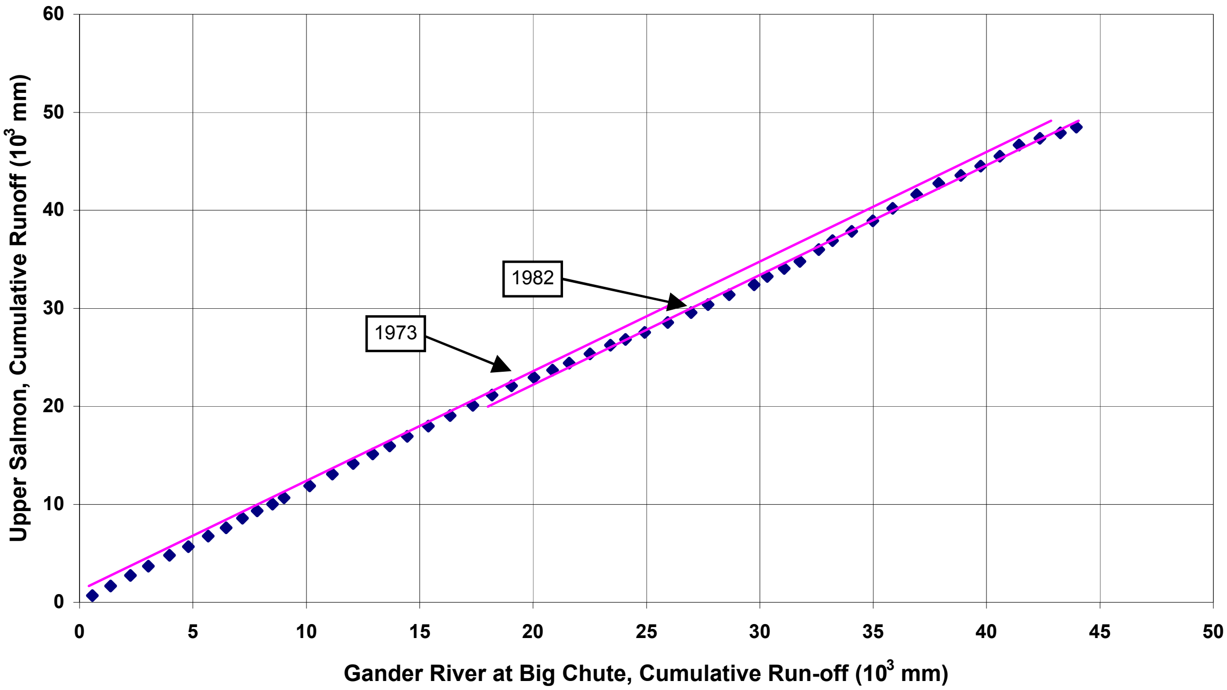

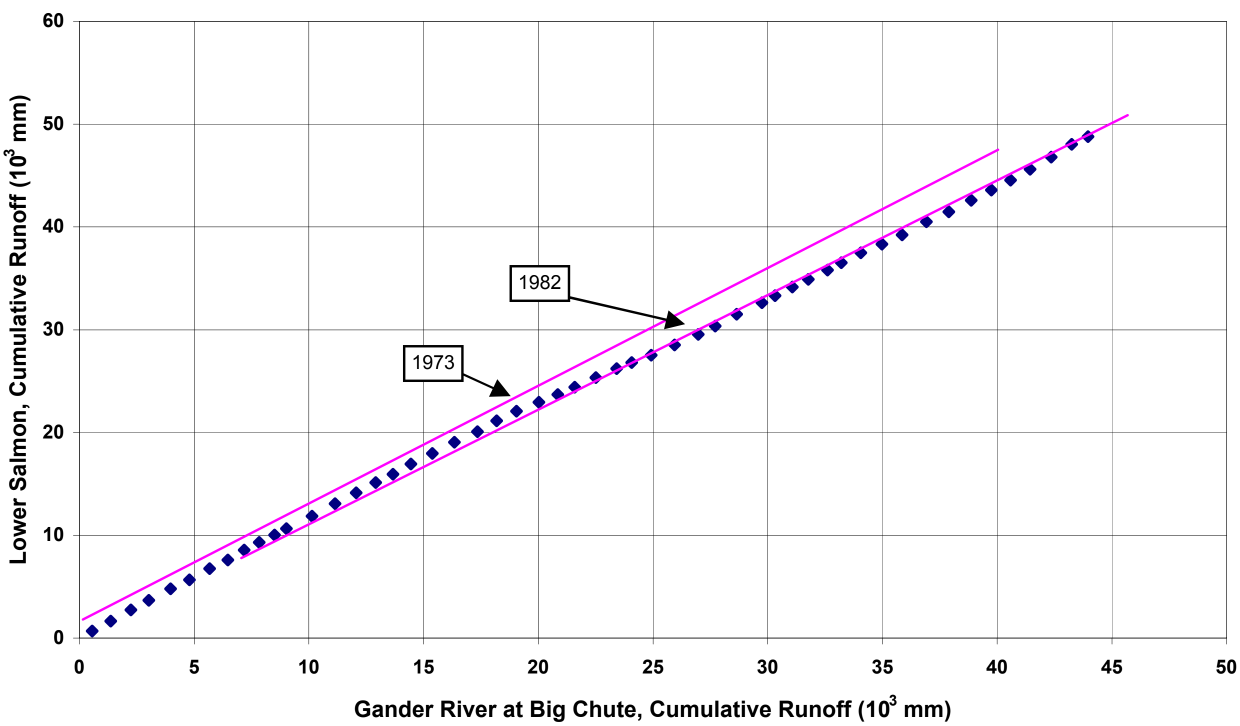

Figure 4.10
Double Mass Curves:
Upper and Lower Salmon Inflows
Island Hydrology Review
Newfoundland and Labrador Hydro

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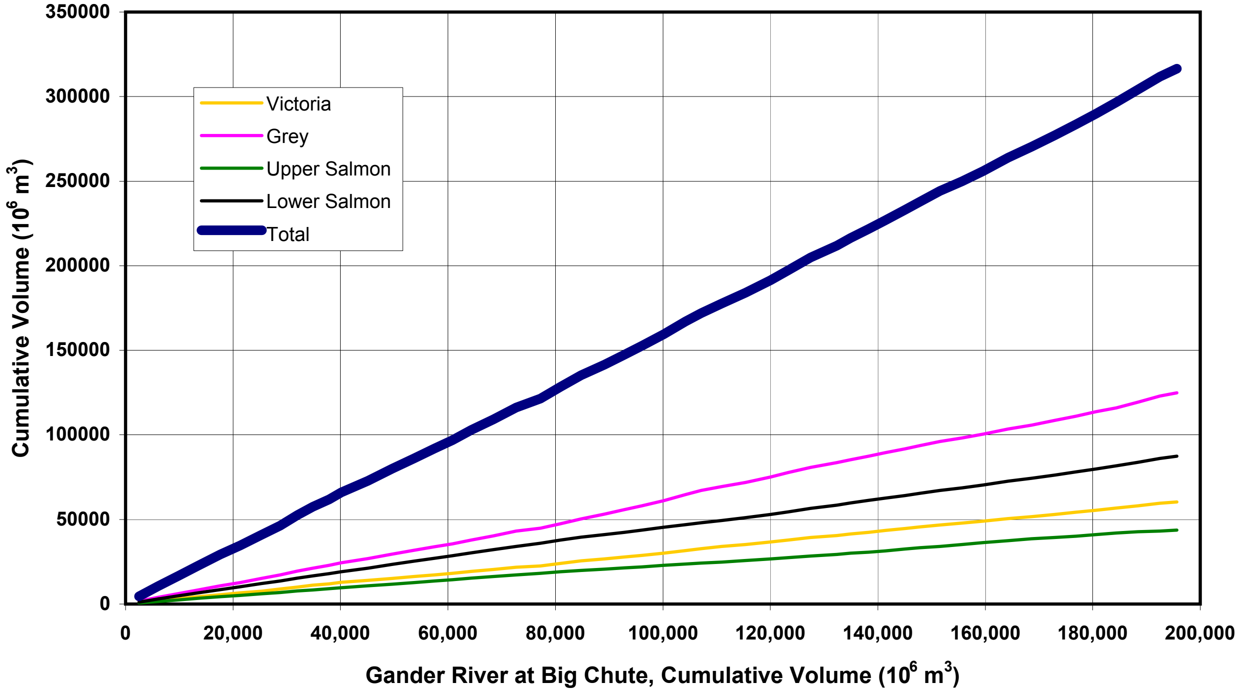

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Figure 4.11
Double Mass Curve:
Bay d'Espoir Total Inflow Volume
Island Hydrology Review
Newfoundland and Labrador Hydro

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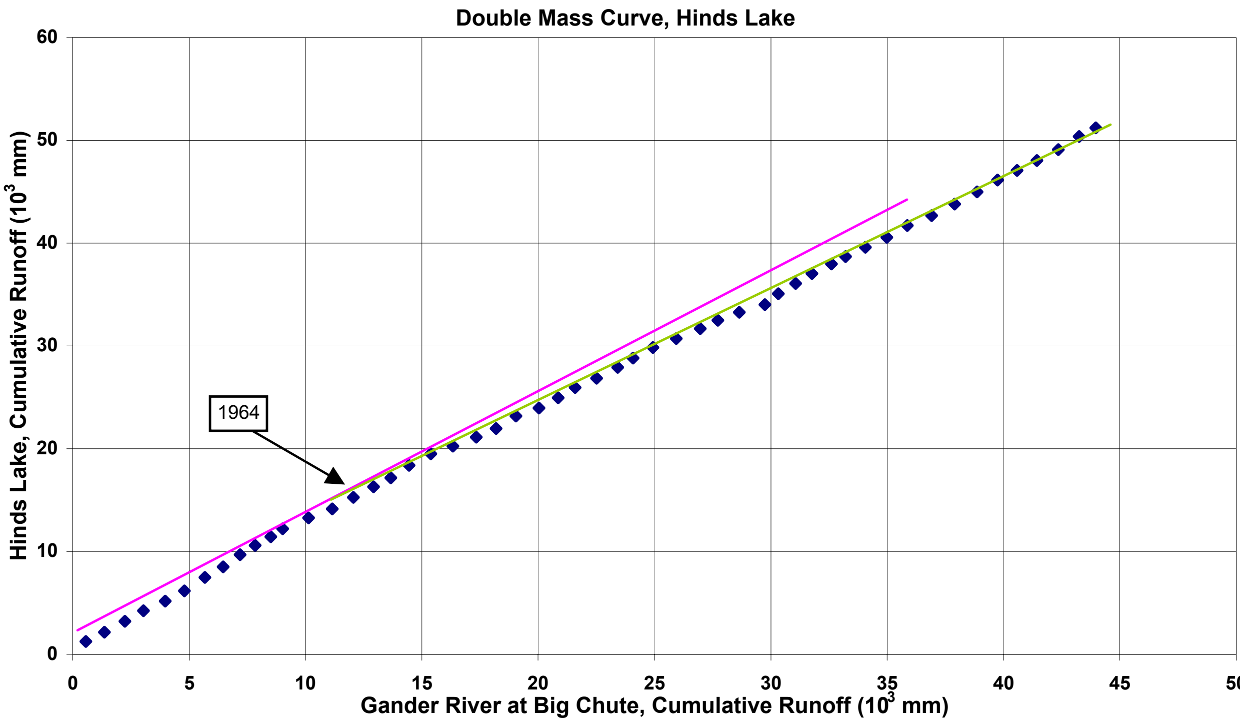


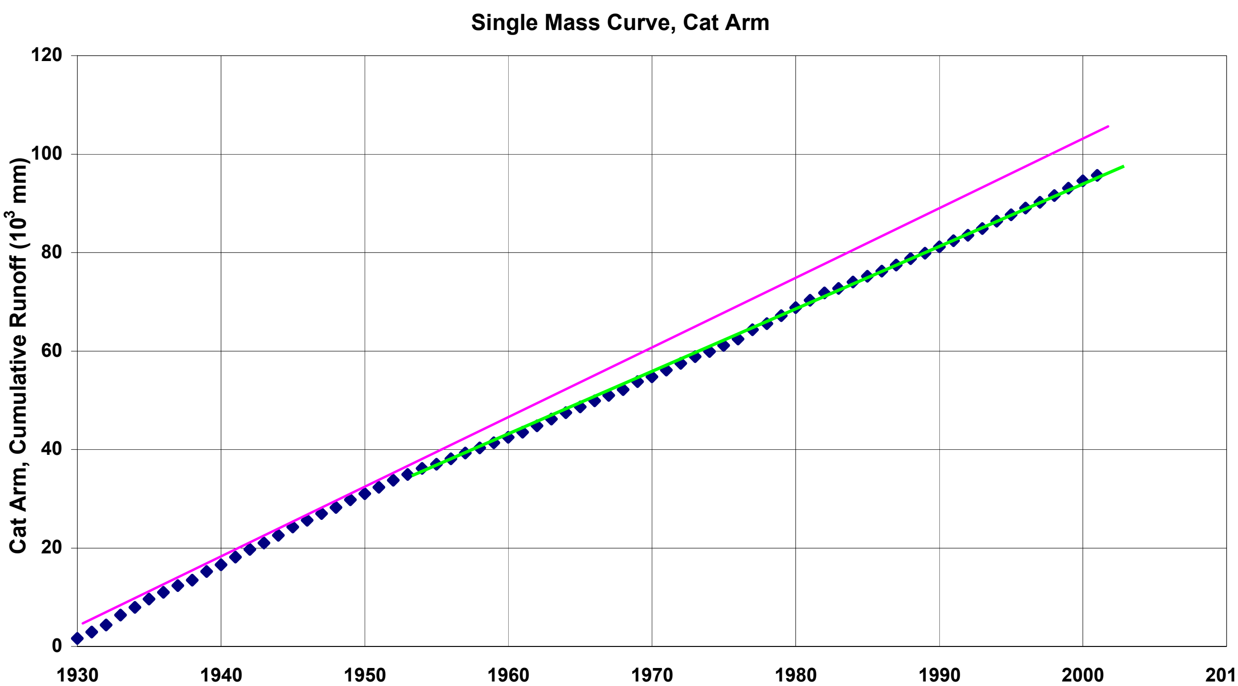
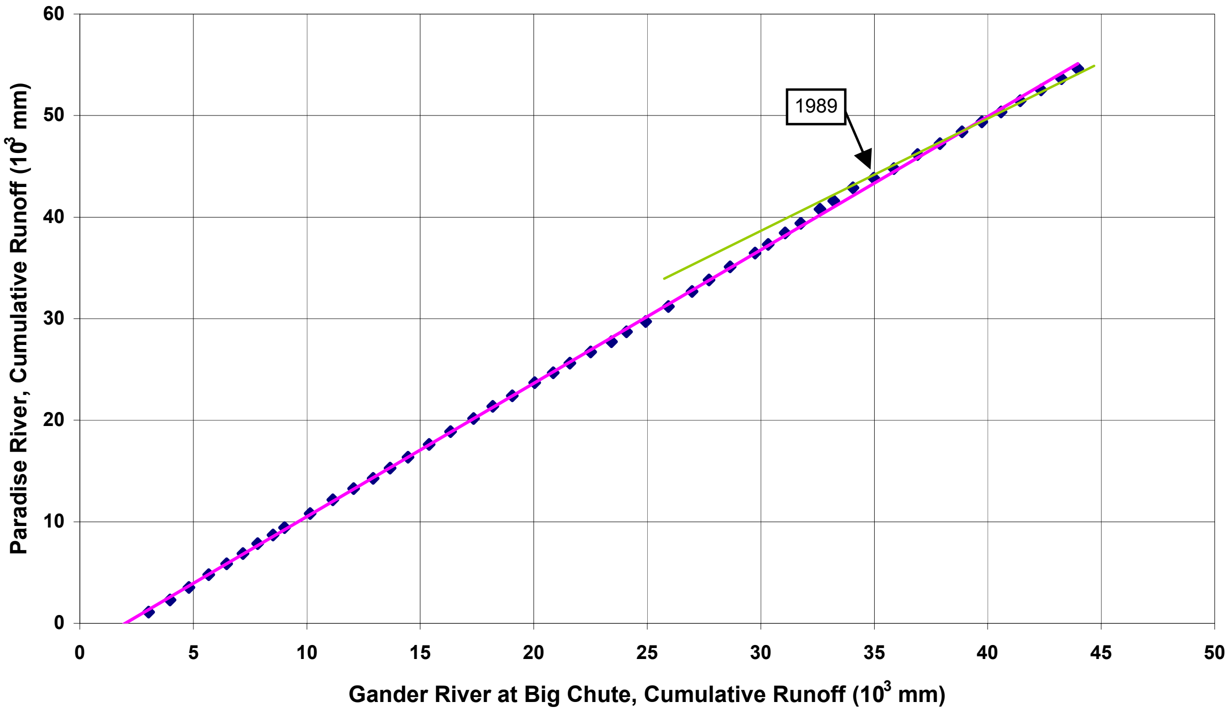


Figure 4.12
Mass Curves:
Hinds Lake and Cat Arm Inflows
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres



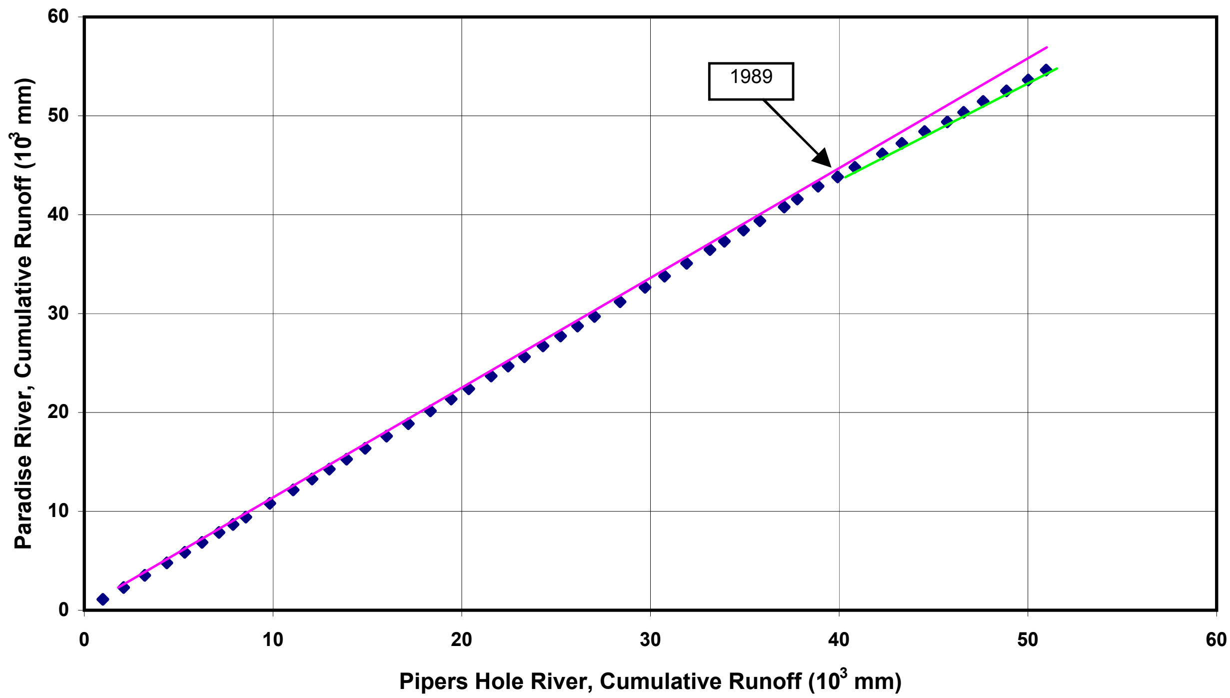


Figure 4.13
Double Mass Curves:
Paradise River Inflow
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

5 Climate Change

5.1 Review of Literature

There is a vast amount of material available in print and on-line regarding the occurrence and impacts of climate change. However, there is very little available that is relevant to the areas of interest to this study, that is, climate change in Newfoundland and Labrador and the impacts of climate change on energy generation.

Appendix I provides a summary of some of the relevant literature reviewed for this study. The main finding from the review is that no conclusive direction or guidance can be drawn from these sources.

5.2 Climate Change Discussion

Mr. William D. (Bill) Hogg provided an expert opinion on climate change and trend analysis for the purpose of this study. Mr. Hogg is one of Canada's foremost experts on hydrometeorology, having worked with climate divisions of Environment Canada for 30 years. Prior to his retirement from EC, Mr. Hogg was Chief of the Climate Monitoring and Data Interpretation, Climate Research Branch of the Meteorological Service of Canada. He has undertaken research on data collection, estimates of extreme events, trend analysis and climate change. Mr. Hogg's opinion is as follows.

> *The overwhelming majority of the world's best climate scientists believe that climate change due to increased greenhouse gas concentrations is occurring globally. As such, Newfoundland is experiencing greenhouse gas-induced climate change superimposed on annual, decadal and centennial scale changes in climate caused by a host of other factors. The complex controlling factors make it extremely difficult to point to observed differences in local climate over the past 50 to 100 years and claim indisputable evidence of greenhouse gas induced climate change. However, the Intergovernmental Panel on Climate Change has associated an observed 1°C increase in global temperatures over the last 100 years with anthropogenic increases in greenhouse gases and Canadian climate scientists have observed a 1°C increase in national temperatures and a 0.5°C increase in east coast temperatures over the same time period.*
>
> *Observed changes in other parameters like precipitation, storminess, etc. are even less clear but physics, climate models and common sense tell us that it is unrealistic to expect that temperature increase will not be accompanied by other changes in climate parameters such as precipitation,*

evaporation, and wind. A consensus in the world science community on what these changes will look like is slowly being achieved, but the one thing that is already abundantly clear is that it is not prudent to blindly assume that the climate conditions experienced over the last 30 to 50 years are adequate indicators of climate conditions to expect for the next 50 years. Regardless of trend, it is important to note that much of our hydrologic design is based upon climate records of the 1950s, 1960s and 1970s. These records reflect lower temperatures and less precipitation. We must now design more robust structures and operating procedures better able to withstand climate conditions exceeding those experienced in the region in the past. With those provisos, it is certainly reasonable to look at changes and trends over the last 50 years, noting differences between conditions now and conditions when structures were designed and first operated. The danger comes when you extrapolate observed changes over the last 50 years for 50 years into the future.

The most important part of trend analysis is in the data preparation. Environmental data collected over many decades includes numerous changes introduced by changes in the measurement program. Changes in observers, instrumentation, location and even the vegetation and nearby buildings can all introduce apparent changes to the record, comparable to the changes introduced by changes in climate. As well, there are very long cycles in climate (e.g. North Atlantic Oscillation-NAO); these introduce apparent trend if you only monitor a portion of the cycle. Finally, there are changes in local or regional climate, possibly reflecting local environmental changes (urbanization, deforestation) or a globally induced change in only the regional climate (a shift in storm tracks because of a change in the NAO). Consequently, it is dangerous to take the raw records from a single station and try to infer too much about global climate change from them.

Environment Canada has spent a lot of effort cleaning up climate datasets for a reduced number of long-record climate stations, including a few in Newfoundland and Labrador, and on analysis of these "rehabilitated" datasets. Trends in heavy precipitation events in eastern Canada have been small over the 20th century. Zhang, Hogg and Mekis (2001) report no significant trend in the 20-year return period event for the country and an upward trend in fraction of annual precipitation falling in heavy events only for stations in northern Canada. There was an observed significant trend in the number of heavy spring rain events in eastern Canada but most other indicators for heavy events showed little trend.

Temperature is more directly related to CO_2 forcing and the historical trend analysis seems more straight forward. Globally and nationally, *temperatures have increased about 1.0°C over the 20th century, while temperatures in Newfoundland and Labrador have gone up about 0.5°C over the same period. Most of the warming in eastern Canada occurred in winter and in minimum temperatures, hence "Canada isn't getting warmer, it's getting less cold."*

Streamflow measurements exhibit the same problems due to changes in measurement programs over the years and are probably even more susceptible to anthropogenic changes in runoff characteristics of the basins that we choose to monitor for long periods. Zhang, Harvey, Hogg and Yuzyk (2001) tried to examine streamflow records with minimal problems. They found no evidence of statistically significant trend in annual streamflow in rivers in Newfoundland and other portions of eastern Canada. Surprisingly, earlier fall freeze-up has lead to a generally longer ice-covered period in eastern Canada, the reverse of trends in the rest of the country.

There has been much speculation that CO_2 induced climate change will be accompanied by an amplification of the hydrologic cycle and increases in the magnitude and persistence of both dry and wet spells. Probably because it is too early in the path of change, it has proven nearly impossible to find historical data that can objectively separate such a signal from the natural year-to-year variability of regional climate. The Canadian Global Climate Model does predict increases in average temperature and precipitation and in 20-year return period daily values of both because of increases in greenhouse gases.

In summary, the only unambiguous evidence of climate change in Canadian historical climate records is for increases in temperature. These increases are consistent with predicted changes due to greenhouse gases and are predicted to continue over the next century, regardless of our efforts to reduce the annual amounts of greenhouse gases we put into the atmosphere, because of the thermal inertia of the oceans and because we have already increased the capacity of the atmosphere to hold in heat.

5.3 Effect of Climate Change on Generation

Any climate change that affects temperature and precipitation in a catchment will impact streamflow and therefore has the potential to affect the generation at any hydroelectric station using the streamflow.

- Temperature changes will affect evapotranspiration, the distribution of precipitation into rain and snow, and the timing and duration of snowmelt.
- Precipitation changes can affect runoff to streams.

A 0.5°C temperature rise in Newfoundland has been identified over the past 100 years, attributed to climate change. For comparison, the following ranges of average annual temperatures for the period of record show much greater variation.

- St. John's 3.6°C to 6.2°C
- Gander 2.3°C to 6.0°C
- Stephenville 2.8°C to 8.0°C

No conclusive evidence or consensus of opinion exists regarding observable or expected changes in precipitation. Similarly, there is no conclusive evidence that there is a trend in streamflow on the Island of Newfoundland that could be attributed to climate change.

Thus though experts agree that climate change is occurring, there is no clear way to take it into account in predicting future energy production. Changes in temperature can have different effects on precipitation and streamflow (increase, decrease, or no change), and the change will not be apparent until it can be identified in streamflow records. An average change in temperature of 0.005°C per year would not be apparent, or significant, in a planning horizon of 20 or 30 years, when the variation in annual average temperatures from year to year can be up to 5°C.

In addition, for systems with a large amount of over-year storage, as is the case with most of Hydro's systems, the impact of a change in temperature is less likely to be significant than it would be for smaller systems. The first impact of a change in temperature in Newfoundland might be a shift in the distribution of precipitation between rain and snow. Where storage is sufficient to store rainfall or snowmelt whenever it occurs during the year, this shift would be of little concern. A change in total annual precipitation could have more of an effect on generation, but to date there is no agreement as to the existence or expectation of either a positive or negative change in precipitation.

The most prudent course of action is to continue to make predictions of future energy generation based on historic series, but to monitor climate change research and periodically assess data series for possible significant trends.

6 Methodology for Calculating Average Production from Reference Sequences

6.1 Description of Present Methodology

Hydro presently calculates its estimate of annual energy by converting the average usable water at each station to energy, using a water-to-energy conversion factor appropriate to each station. These conversion factors are calculated from plant data, and are not the subject of the present study. They can generally be assumed to be accurate where generating units have been tested.

The calculation starts with average inflows, taken as the average of the reference sequences, as described in Section 2. Not all the inflows can be used for generation; in periods of high flows, some will be spilled. In periods of low flow, and at other times as well, water must be released to support downstream fisheries. In order to calculate the usable water, Hydro first subtracts the average historic spill at each station from the average inflow. The average historic release for fisheries compensation is then subtracted, and the result is useful outflow for energy production. This value is multiplied by the water-to-energy conversion factor to give the estimate of average annual energy.

A sample calculation of 2000 Hydroelectric Plant Average Energy along with the values used to determine average spills is included in Appendix J. In the spill table, the spill appears to have been the same for many years in succession; this apparent similarity is simply because the total volume spilled in the period was distributed evenly over the years.

Hydro has made some adjustments to the average spills. In particular, it does not include Lower Salmon spill before 1975. The reservoir at Bay d'Espoir actually started spilling before 1975, but these values are not included. As explained by Hydro in the 2001 Board rate hearing, the conditions prior to 1975 are not representative of present conditions. The units were not being fully used because of insufficient load, and therefore water was spilled that today would be used in energy production.

Energy from the small hydro stations at Snooks Arm, Venam's Bight and Roddickton is taken as the average historic production. The value is about 6 GWh annually, about 0.14 percent of total production.

6.2 Comments on Methodology

The current Hydro methodology has the advantage of being simple and consistent, relying on historic data. Assuming the inflows and the energy conversion factors are correct, comments on the methodology itself are as follows.

1. Different Sequence Lengths

The reference inflow sequences used for determining the available water for different stations have different lengths. The Cat Arm and Hinds Lake sequences start in 1930 and 1927 respectively, whereas the Bay d'Espoir inflow sequences start in 1950. If all the data in a series are equally accurate, then in principle the longer the record, the better the estimate of the mean. The difference in sequence lengths is not important.

2. Spill and Fisheries Compensation Releases

The periods of record used for estimating average spill and fisheries compensation and for estimating average inflows are different. The inflows are based on the full length of the inflow series, over 50 years. The spill and fisheries compensation flows are based on the period of the historic record only. The spill table in Appendix J shows the lengths of these records.

Spill from the larger reservoirs tends to occur infrequently, that is, there can be a series of several years with no spill, followed by a year with spill. The number of years over which the spill is averaged may thus be important. With the current methodology, there is no explicit way to handle the inconsistency in the lengths of records. The energy value of the spills and fisheries compensation amounts is relatively small, but they do represent value.

3. Accounting for Changes

Using historic values for spill and fisheries releases has the advantage that it takes into account some of the unpredictable elements that affect hydro generation, such as varying demands for fisheries compensation and unforeseen outages or malfunction of release structures. This method does assume, however, that historic operating conditions and requests for fisheries flows will be the same in the future as they have been in the past. Up to now, Hydro has taken changes into account using good judgment, such as by counting spill only from 1975; again, there is no explicit way to evaluate the effects of changes.

6.3 Assessment of Methodology

Hydro's present methodology has given a reasonable estimate of average annual energy. Given the comments above on accounting for spill and other releases, however, some form of computer simulation or modeling would be preferable for preparing spill and energy estimates. Although the results would likely be similar to those obtained by the present method, computer simulation would provide a consistent, transparent and defensible basis for the estimates. Good judgment would still be required in the selection of the inputs, but the model would provide a means of testing the outcomes of the inputs selected.

The energy from the small stations, Snooks Arm, Venam's Bight and Roddickton is a small proportion of the total system energy, and using the historic value is appropriate.

7 Overview of Practices in Other Jurisdictions

In addition to asking Hydro to address technical issues, the Board also requested Hydro to provide an overview of practices in other jurisdictions relating to the calculation of average annual energy. This information was obtained through a telephone/email survey of utilities and regulators.

7.1 Survey Procedure

The procedure for carrying out the survey was as follows.

1. Identify utilities in Canada and the U.S. with a large proportion of generation from hydroelectric resources.

2. Identify a preliminary contact within each of these utilities; call or email this contact to confirm that the person contacted was an appropriate person to respond. If not, ask the preliminary contact to provide an alternate appropriate name.

3. Call or email the appropriate respondent to administer the survey. The same questions were used for both the phone and email surveys. If the questions were answered on the telephone, the survey form was filled and returned to the respondent for editing. The respondent's returned form or email response became the official record.

4. Identify and survey regulating agencies. The procedure for identifying the appropriate person within the regulating agency was similar to that for the utilities.

5. Compile responses.

7.2 Selection of Utilities and Regulators

Utilities in Canada and the U.S. were selected from lists of all the utilities in the subregions of the North American Electric Reliability Council (NERC), shown in Figure 7.1. The members of the eleven sub regions of NERC account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. Utilities were included in the survey if they have at least 200 MW of hydro generation, making up 50 percent or more of their total generation. These utilities are comparable in scale with Hydro, which has about 1600 MW of total generation, of which about 1000 MW is from hydroelectric resources.

Twenty-two utilities satisfying these criteria were identified. In addition, three utilities which are members of the Hydraulic Integrated Resource Management Interest Group (HIRMIG), a committee of the Canadian Electrical Association, were also included. Their membership in HIRMIG indicates their interest in their hydroelectric resources.

If the utility respondent said that a regulating body set the utility's rate, then that regulator was surveyed. Contacts in provincial regulating boards or agencies were found by contacting the agency or if necessary through the provincial governments. The state regulating agencies in the U.S. are all listed with the National Association of Regulatory Utility Commissioners, and this source was used to identify contacts.

The contact and response rates were as follows.

Utilities contacted	25
Utilities responding	10
Regulators contacted	6
Regulators responding	3

All but one of the Canadian utilities contacted responded. The U.S. utilities that did not respond were primarily in California and Washington. Of the responding utilities, the hydroelectric capacities ranged from 211 MW to 30 680 MW, accounting for 56% to 100% of total electrical generating capacity.

Copies of the survey questionnaires to utilities and regulators are provided in Appendix K. A summary of the responses from utilities and generators is also in Appendix K.

7.3 Utility Responses

The questions were grouped into two categories, those relating to the development of the estimates of production from hydroelectric resources, and those relating to the uses of the estimates.

7.3.1 Development of Estimates of Hydroelectric Production

1. Do you (or does someone else in your organization) develop estimates of expected production from your hydroelectric resources?

All respondents said yes.

2. *What estimates do you develop? e.g., mean, median, other statistics*

Most develop estimates of mean hydraulic production, two use percentiles; three use, or will soon use, probabilistic estimates, although these are for short term estimates.

3. *What methodology is used to estimate hydraulic production?*

All use computer simulation models, varying in number and complexity.

4. *If estimates are developed from a sequence, is it an historic record or synthetic sequence?*

Almost all use historic records. Most use flows derived from plant data; some use historic weather data to develop inflows, a few use adjusted flow records. One respondent uses a synthetic record.

5. *What length of record do you use?*

The record length varies from about 25 years to over 70 years.

6. *How did you (or others) select the record length? If longest possible, what is rationale?*

The rationale given by most respondents for choosing a particular length of record was that it is the longest possible, implicitly stating that this is to be preferred. One explicitly stated that all data were used and assumed to be equally reliable. One was required by the regulator some years ago to use a length of 20 years but the decision was reversed. The utility prefers to use the full length of record because it reflects hydrologic variability.

7. *Was the entire length of record developed from the same set of data or using the same methodology?*

Most utilities said yes, two said no (in those cases it had been developed from both flow data and plant data), and one was unsure.

8. *Do you drop any data or curtail it to a common period?*

Most do not drop or curtail data, however, one indicated that water years are commonly curtailed for operational planning purposes and another curtailed data to provide a common data set.

9. Why or why not?

The only reason given for curtailing data in the early part of the record is to have a common period of record for computer modeling of systems. If there are several plants being modeled together, they each must have a common period of record. Three utilities curtail data in the recent part of the record until it can be assessed or adjusted, for example to account for current water uses. Another utility indicated that water years having low probability of occurrence are often omitted in near term operational studies.

10. If so, what are your criteria for curtailing a record?

Not applicable, except as in question 9 above.

11. Is trend analysis used in the development of expected annual hydraulic energy production estimates? Trends in what? (e.g., precipitation, streamflow, development?)

No respondent used trends in preparing streamflow estimates, although two mentioned that they might do near term adjustments (wet/dry). Three utilities indicated that the reason was that there appears to be no evidence of trends in streamflow. One utility takes account of trends in development of the basin (land uses, water extractions).

12. What are you (or your utilities) doing to assess climate change impacts on the hydroelectric industry?

Most utilities were taking no action on climate change. One utility indicated that it is doing some review and research, as well as some sensitivity analysis. Another indicated it has meteorologists and hydrologists who assess climate change and monitor climate indices.

7.3.2 Uses of Estimates

1. For what purposes do you use the estimates of hydroelectric energy?

See responses to questions 2 to 4 below.

2. Do you use them in operations? (e.g. reservoir planning, water management, production costing)?

All said yes, except one of the utilities that has only a small proportion of hydro generation. One uses historic flows for most purposes, but real-time flows from stream gauges for day to day operations.

3. Do you use them in long term planning (typically generation expansion planning)

Eight said yes, two no.

4. Do you use the estimates of hydraulic energy to set rates ?

Six said yes, four no.

5. Do you provide the estimates to others outside your organization, e.g., Are you required to provide them to a regulating agency or others?

Five provide them to rate-setting agencies, two to other members of a hydro or water sharing group, one provides study results to ratepayers and public agencies, and two do not provide them to anyone else.

6. If so, does the regulating agency set any requirements on how they should be derived – e.g. length or type of record.

Seven said no, or stated that the question does not apply. In one case the respondent was unsure, and in one American jurisdiction, the regulator set the length of record. This jurisdiction has a mechanism for recovering additional costs between rate hearings from the consumer.

7. What is your regulating agency or agencies?

Most utility respondents cited either state or provincial utilities boards. Three named the U.S. Federal Energy Regulatory Commission (FERC) which regulates utilities for various purposes but does not set rates, and one named a market operator.

7.4 Regulator Responses

Because the rates were not set by regulating agencies for many of the utilities, and of these, few agencies set any requirements relating to energy estimates, the regulators were asked only three questions, as follows.

1. Does your organization set or approve rates for the sale of electricity by hydroelectric power producers in your jurisdiction? If yes, please briefly describe the extent of your authority, and state your area of jurisdiction.

Only one of the three responding agencies actually sets or approves the rates for utilities in its jurisdiction. Of the remaining, one sets rates for companies involved in interstate transmission and the other treats electricity as a commodity allowing the market to determine the rate.

2. *Does your organization require hydroelectric power producers to provide estimates of expected production, for the purpose of setting or approving rates?*

Of the three respondents, one said yes, two said no.

3. *If yes to #2, does your organization set any requirements on how such estimates should be derived – e.g., methodology, type of record, length of record.*

Only one of the regulators sets the methodology for determining estimates. About eight years ago the utility was required to use a 20 year period as the basis for setting rates. Upon appeal this decision was reversed and the entire hydrological record is now used.

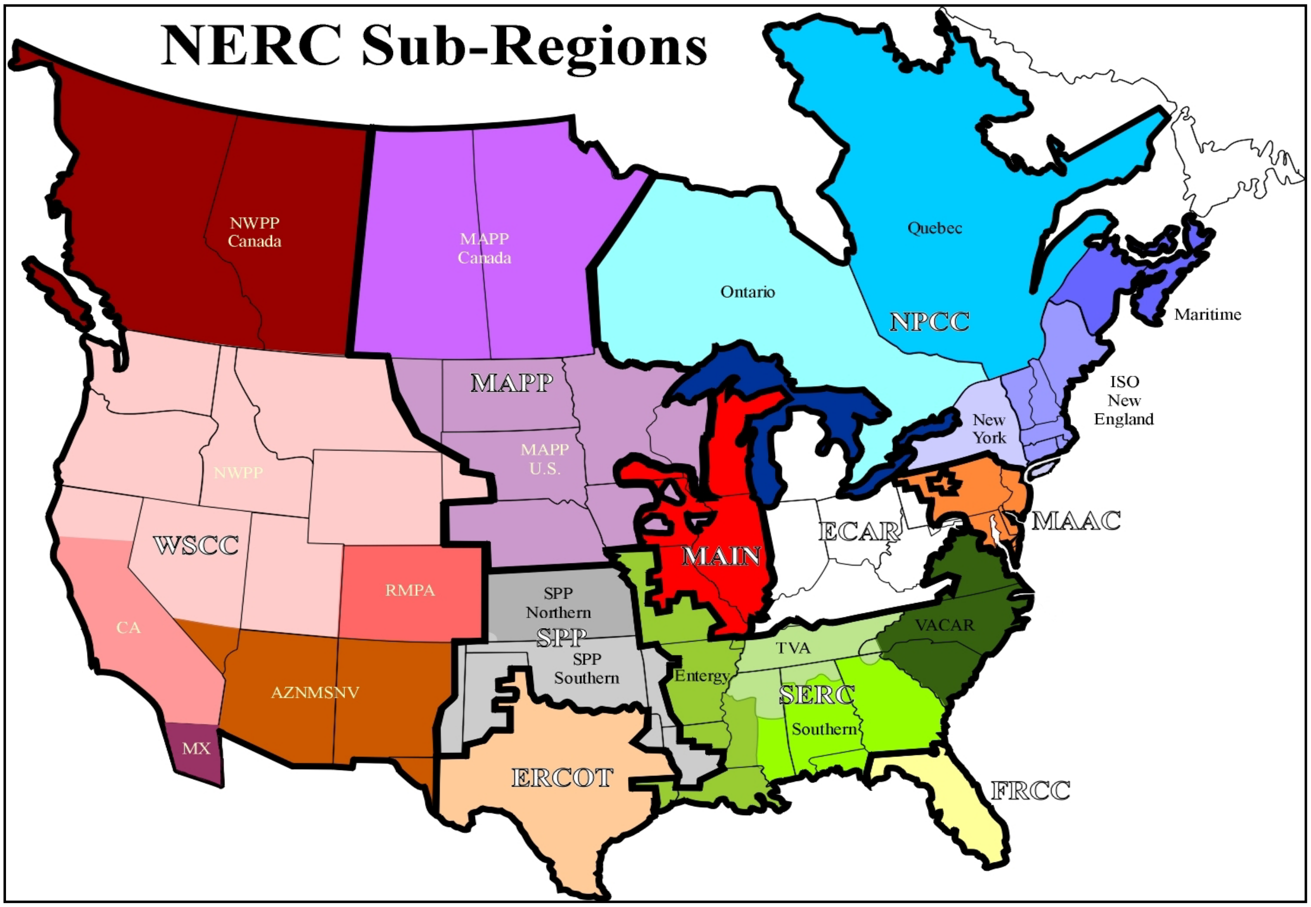
7.5 Summary of Survey Results

All of the responding utilities develop estimates of expected production from hydroelectric resources. Almost all of them use a historic sequence that is based on the entire length of record available.

Most utilities develop the data from the same data set and very few curtail that data. Only two reasons were given for curtailing, the requirement to have a common period of record in a computer model and the need to assess and adjust recent water years, for example to account for changes in water use. Climate change is not a priority for most utilities, however, a few are considering and researching its effects while others are planning to do so in the near future.

Estimates of hydroelectric energy are used by almost all utilities for operational and planning purposes. Just over half use energy estimates in rate setting with most providing these estimates to a regulatory agency. Only one regulator sets requirements on how the estimates should be derived. The majority of the utilities indicated that their regulatory agency is a provincial/state agency; some are regulated by FERC, and one by a market operator.

The findings of this survey corroborate the information tabled by Hydro at the most recent rate hearings (P.U.7(2002-2003)) regarding the practices of utilities in other jurisdictions.



NERC - North American Electric Reliability Council
ASCC - Alaska Systems Coordinating Council
ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAAC - Mid Atlantic Area Council
MAIN - Mid-America Interconnected Network
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Council
SERC - Southeast Electric Reliability Council
SPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council

Figure 7.1
NERC Sub Regions Diagram
Island Hydrology Review
Newfoundland and Labrador Hydro

SGE Acres

8 Discussion

The RFP identified three main items for review:

- data reliability and methodology;
- long term trends; and
- climate change.

This section brings together and discusses the results of the analysis presented in previous sections of the report on these items.

8.1 Data Reliability and Methodology

The review and assessment of data reliability and methodology addressed four concerns:

- reliability of the source data (possibility of technological change in data collection leading to invalid data);
- development of reference inflow sequences (data sets) from the source data;
- methodology for calculating average energy from the reference inflow sequences; and
- use of the same sequences or data sets for rate setting, operations and planning.

Each of these is discussed below.

8.1.1 Reliability of Source Data

The EC streamflow data used to develop the pre-project Hydro series can be assumed to be accurate, at least since 1950. The quality of the pre-1950 streamflow data is unknown since it was collected by others but the post-1950 data has been quality controlled by EC and is therefore reliable.

The post-project Hydro series were developed by standard backrouting using calibrated curves for structures and generating units, an accurate method where calibrated information is available.

8.1.2 Development of Inflow Sequences from Source Data

The mass curves and the step trend tests showed that for several reservoirs the Hydro inflow sequences are internally inconsistent. The break point tends to occur around the time when the projects came on line; this is not unexpected since the methodology for developing the inflows changed. The pre-project flows were estimated by various methods as described in Section 2. Although the source data are generally valid, more recent data suggests that the transposition of data from gauged basins to the Hydro basins may be incorrect. The post-project flows were developed from measurements of water levels and outflows, which generally are accurate, especially at power stations.

Internal inconsistencies in the sequences are not in themselves a reason for rejecting them, particularly since most of the source data on which they are based are valid. Techniques similar to the runoff and correlation studies carried out to develop the inflows at the time of the feasibility studies could be used to revise the sequences with the significant advantage that there is now a much longer history for correlation. The analysis would include checking to make sure the pre and post project series have similar distributions and show no breaks in the mass curves. For the post-project series, the information used for backrouting would be checked if there are anomalies.

Rectifying the streamflow sequences is expected to have only a minor effect, if any, on the estimate of average energy. It will however, provide a more consistent basis for the energy estimates and other purposes.

8.1.3 Methodology for Estimating Annual Average Energy

There are two questions with respect to Hydro's methodology:

1. the appropriate length of the reference inflow sequences to use in estimating the average energy; and
2. the appropriate methodology for developing the estimate from the sequences.

1. Appropriate length of reference inflow sequences: The longer the series used to estimate the mean, the lower the sampling error, and therefore the better the estimate. Hydro should therefore use as long a sequence as can be accurately derived from valid data sources. For most of the Hydro basins, this is probably from around 1950 to the present. A longer series gives a more complete representation not only of the mean but of other hydrological characteristics.

There is little or no evidence that trends in streamflow are occurring in EC's basins on the Island, and the apparent trends in a few of the Hydro basins may disappear once the sequences are made internally consistent. The runs analysis also showed that it is pointless to try to forecast flows for the next year or several-year period based on recent hydrology. At present, therefore, the expected value for future flows is the mean of the historic flows. The longer the period of reliable record used to estimate this mean, the more accurate it is likely to be.

2. Appropriate methodology: Hydro's approach of converting usable flow to energy is straightforward, and probably results in a similar estimate of average energy as would be obtained using other methods. Conceptually, however, it has some potential sources of error. The first is that the estimates of average spill and fisheries releases are based on lengths of record inconsistent with the inflow sequences, and the second is that it does not explicitly account for changes in operation.

A computer model that simulates flows and operations for all basins would be appropriate, with corrected sequences for all stations from the early 1950's to the present.

8.1.4 Use of Same Estimates for All Purposes

Hydro requires as sound a base as possible for its varied uses of the inflow sequences, for rate setting, maintaining a reliable system, financial planning, forecasting fuel purchase requirements, dispatching units, long term planning, and so on. All these uses require the best possible estimate of hydrology; there is no reason to use a different reference sequence for one purpose than for another.

8.2 Long Term Trends

The review of EC's streamflow records and Hydro's inflow series showed little or no evidence of trends in streamflow. Some of the EC precipitation data series showed upward trends, but this was not reflected in the EC streamflow series. Of the twelve streamflow series, one had a slight upward trend, and one had a slight downward trend. One river had a significant upward trend; several years of missing data in the early part of the record make it difficult to assess the validity of this trend.

Of the Hydro series, the one with the longest internally consistent inflow sequence is Hinds Lake. That series shows no trend if the entire series 1927 to 2001 is considered, an upward trend in the period from 1950 to 2001, and no trend from 1972 to 2001. Cat Arm also has a long series, although the quality of the pre-1950 data from which it was derived is unknown. That series shows a mild downward trend for the 1930 to 2001 period, mild upward for the 1950 to 2001 period, and no trend for the period 1972 to 2001. These long records suggest that overall there is no trend but that the period selected for analysis will influence the results.

Three of the other five Hydro series, Paradise River, Lower Salmon and Upper Salmon, show no statistically significant trends. The other two, Victoria and Grey, show apparent upward trends. Further examination of the records indicated that these apparent monotonic trends are primarily the result of step trends due to a change in methodology, as previously discussed.

8.3 Climate Change

A review of the relevant literature and expert meteorological opinion indicate that there is wide agreement that climate change is occurring. The amount and direction of change in precipitation on the Island of Newfoundland is uncertain, and the resulting effect, if any, on streamflow is even less certain.

9 Conclusions and Recommendations

9.1 Conclusions

The conclusions of this study are as follows.

Length of record: As future hydrology is impossible to forecast, the only reasonable basis for planning activities, operations, and rate setting is to adopt historic reference inflow sequences as the best available estimate of future hydrology. It is desirable to use as long a hydrologic record as possible for the reference sequences to minimize the potential errors in estimates of mean and variability. A sample size of at least 30 years is desirable, but a longer record is preferable. Hydro is fortunate to have records from 1950 onwards at each of the stations key to its purposes, providing a respectable record length of 52 years, increasing with time.

The sources on which the streamflow sequences are based are sound, with the exception of the early part of the Cat Arm sequence. The technological improvements in data collection from 1950 to the present have not affected accuracy and should not affect the selection of the length of record in this period.

Characteristics of the sequences: The inflow sequences should be internally consistent, be free of errors, and exhibit as well as possible the statistical characteristics of anticipated future hydrology.

Various methods have been used to develop the present Hydro sequences. The method of flow estimation is irrelevant, however, as long as the foregoing requirements are met.

The Hydro records have some problems in regard to internal consistency, arising principally from changes in methods of flow measurement and internal basin water balance accounting (in the Bay D'Espoir basin). These deficiencies can (and should) be corrected. Aside from these internal inconsistencies, the sequences appear to be free of systematic and random errors.

The similarity of statistical characteristics of future inflows to the reference sequences is an open question. The most likely cause of the reference sequence not being representative of future hydrology is climate change. Examination of the streamflow records and Hydro inflow series on the Island does not reveal any definitive recent trends or changes attributable to climate change, nor is it possible at this point to predict the effects of climate change on future inflows. In any case, such changes are likely to occur slowly over a long period of time relative to the normal planning and rate setting horizons for hydropower systems. Thus, the hydrology of record, given that it satisfies the foregoing requirements for quality, is still the best basis for estimating future conditions.

Use of reference sequences: The same reference inflow sequences should be used for all purposes (for example, investment planning, hydrologic risk management, operations planning, rate setting) to ensure that decisions made in one activity will not be at odds with those from another, that is, to avoid biasing analytical results with estimates based on selectively chosen sequences.

Methodology: Computer simulation of reservoir operation and power production from the hydroelectric system would be a more appropriate methodology than the one presently used by Hydro to calculate the expected annual average energy from hydraulic resources. In particular, since spills are an important cause of lost energy, they should be considered in the estimate.

Practices in other jurisdictions: Utilities without exception prefer to use the longest possible record; they are aware of the possibility of trends due to climate change, but at present are not making any speculative changes to their energy estimates; they almost all use computer simulation models for various purposes, including estimating average annual energy.

9.2 Recommendations

The recommendations arising from this study are as follows.

- The longest reliable reference inflow sequence (period of record) should be used for all Hydro's operation, planning and rate setting purposes. The availability of good source data supports a start date in the early 1950s for most stations.

- The inflow sequences presently used by Hydro should be corrected to ensure internal consistency.

- The same estimate of average annual energy from hydroelectric resources should be used for rate setting operations and planning.

- Computer simulation of the operation of the hydroelectric system using the reference inflow sequences should be used to estimate energy production and spill from Hydro's hydraulic resources. Hydro should review its inhouse models and other models available and select one for these purposes. The above-noted corrections to the inflow sequences should be complete prior to simulating operations under this model.

- Recognizing that rectification of the inflow sequences and selection of a computer model will require some time, Hydro should continue to use the current methodology and inflow sequences for energy estimates. The present records even with minor inconsistencies will give better estimates of expected flow than shorter records.

- Hydro can decide as a matter of convenience whether it includes Paradise River in the computer simulation model or not. As a run-of-river plant, it does not affect the operation of the rest of the system. Whether the energy estimate is developed separately or modeled with the other plants, the estimate should be reviewed when the inflow sequence for Paradise River has been rectified.

- Since the small hydro stations (Roddickton, Snook's Arm, and Venam's Bight) represent a very small fraction of Hydro's generation, Hydro does not need to make any changes to its estimates from these stations.

- Most climatologists agree that climate change is occurring. Hydro should therefore continue to follow relevant research studies and periodically assess the possibility of trends in its streamflow series. If more definitive evidence of trends is found, Hydro should at that time make appropriate adjustments to its energy estimates.

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Appendix A

Request for Proposals

HYDRO
THE POWER OF COMMITMENT

File No ________.

NEWFOUNDLAND AND LABRADOR HYDRO
Head Office St. John's, Newfoundland P.O.Box 12400 A1B 4K7
Telephone (709) 737-1400 • Fax (709) 737- 1231 – Website: www.nlh.nf.ca

SGE Acres Ltd.
4th Floor Beothuk Building
20 Crosbie Place
St. John's, Newfoundland
A1B 3Y8

RE: Request for Proposal (RFP) – Island Hydrology Review

You are invited to submit a proposal for a comprehensive review of Newfoundland & Labrador Hydro's (Hydro's) methodology for estimating annual hydroelectric capability for production forecasting and rate-setting purposes, and to recommend the most appropriate means to develop the estimate. The proposal is to be submitted to our Material Management Department, 4th Level, Hydro Place, 500 Columbus Drive, St. John's before noon, local time, on October 18, 2002.

The scope of the service contemplated consist of the following and shall be carried out under the supervision of our Operations Planning Engineer (telephone 709-737-1964); who is also your contact in the event you require any clarification of this RFP.

Scope of Service

The work of the consultant will address questions in four separate but related areas:

1. **Data Reliability and Methodology**. Assess the reliability and accuracy of Hydro's existing hydrological records to determine their relevance and applicability to the planning and forecasting process. Also to assess Hydro's methodology for developing it's estimates of annual hydroelectric capability. Specific areas to be addressed will include:

   - Technology changes since records have been kept, and the accuracy of measurements through differing technologies employed in the past as it relates to Hydro.
   - Inflow determinations before and after project development.
   - Whether or not spills are to be reflected in the development of the estimate, and if they are, to recommend the most appropriate means of doing so.
   - An overview of the practices of other hydroelectric producers (in Canada and where appropriate, the United States) regarding the use of historic data.
   - An overview of the practices in other regulated jurisdictions regarding the length of hydraulic record and methodologies used in setting hydraulic production for operations planning and rate-setting purposes.

- Opinion on whether or not (and the extent to which) technological improvements in data collection should influence the choice of data set in determining the historical flows for the purposes of estimating expected annual hydroelectric production.

- Opinion on the merits (or merits to the contrary) of using the same methodology and dataset for rate-setting purposes as is used for planning and operating purposes.

2. **Long Term Trends.** Assess Hydro's historic inflow records to determine if long term trends are emerging with respect to inflow patterns to Hydro's watersheds on the island of Newfoundland. Specific areas to be addressed will include:

    - Assessment of whether long term trends are present.

    - Assessment of the historic record that best describes any long term trends.

    - Assessment of the applicability of trending analysis to the determination of expected annual hydraulic energy production estimates.

    - Overview of the practices in other jurisdictions (in Canada and where appropriate, in the United States) regarding the use of trend analysis in the development of expected annual hydraulic energy production estimates.

    - Opinion regarding the use of trend analysis for developing expected annual hydraulic energy production estimates.

3. **Climate Change.** Provide an opinion on whether or not climate change is taking place on the island of Newfoundland, and if so, how climate change is expected to affect hydroelectric generating capability. The work will also provide an overview of what is being done in other jurisdictions to assess climate change impacts upon the hydroelectric industry.

4. **Recommendations.** Provide recommendations on the development of annual hydroelectric generating capability estimates specific to:

    - Appropriate period of historic record to use when developing estimates of expected annual hydroelectric capability, both for operating and rate-setting purposes.

    - Appropriate methodology for developing the expected annual hydroelectric capability, both for operating and rate-setting purposes.

Schedule

The scope of services is to be completed by November 29, 2002, with an update/progress report to be provided to Hydro by November 8, 2002.

Remuneration for the Service

Remuneration for the service will be on a lump-sum basis, payable at completion of the services and acceptance of the deliverables by Hydro. The total cost for the proposed work, except for those items directly related to providing expert opinion at a regulatory hearing, is not expected to exceed $50,000 ($Cdn).

Consultant's Registration Requirements

The consultant shall be authorized to do business in the Province of Newfoundland and Labrador prior to performance of the services. Where the consultant is a corporation, it shall be registered to carry on business in compliance with the laws of the Province of Newfoundland and Labrador and shall be registered in good standing with the Registry of Companies of Newfoundland and Labrador.

Secrecy

Notwithstanding the fact that the deliverables of the services will become a part of the public domain, the consultant shall exert its best efforts, to retain as confidential and not divulge, other than to persons specifically designated and approved by Hydro, environmental, financial, technical or schedule information and data or any additional information designated as confidential by Hydro that was furnished to the consultant by Hydro or was acquired by the consultant in the preparation and submission of the report. The consultant shall treat all such information as confidential and the foregoing shall not apply to information and data which:

a. Were in the consultant's possession or was previously known by the consultant prior to submission of its proposal in response to this RFP; or

b. Becomes known or published through some agency other than the consultant from third parties not connected with the project or with the performance of services; or

c. Becomes part of the public domain through no fault of the consultant.

Evaluation of Proposals

The evaluation of proposals will be based on, but not limited to, the following considerations:

a. All relevant legal and financial considerations;

b. Capability of the respondent, based on the relevant experience of the respondent and the personnel to be assigned to the services;

c. Technical adequacy of the proposal including appreciation of the scope of the services and proposed methodology to undertake the study; and

d. Fee for performance of the services.

Deliverables

The results will be provided in a written report to Hydro, which will be provided to the Public Utilities Board and the public. The consultant should be prepared to provide expert opinion and evidence relative to this topic at a regulatory hearing should the requirement arise.

Yours truly,

Director, Materials Management and Administration

cc: David Harris
Rob Henderson
Jim Haynes

Appendix B

Hydro Reference Inflow Sequences

Table B.1
Victoria
Reference Inflow Sequence

Sequence Length: 52 years
Plants in Service: 1967 (Bay d'Espoir), 1983 (Upper Salmon)
Area (km^2) 1058

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1950	1065.28	33.76	1007
1951	1155.36	36.61	1092
1952	1070.38	33.92	1012
1953	1056.78	33.49	999
1954	1201.50	38.07	1136
1955	998.16	31.63	943
1956	1088.22	34.48	1029
1957	1190.15	37.71	1125
1958	1282.48	40.64	1212
1959	967.30	30.65	914
1960	911.52	28.88	862
1961	870.74	27.59	823
1962	1162.12	36.83	1098
1963	1208.00	38.28	1142
1964	1076.88	34.12	1018
1965	950.30	30.11	898
1966	948.34	30.05	896
1967	1109.19	35.15	1048
1968	1076.89	34.12	1018
1969	1360.92	43.12	1286
1970	765.95	24.27	724
1971	1501.20	47.57	1419
1972	1467.09	46.49	1387
1973	1176.58	37.28	1112
1974	1078.58	34.18	1019
1975	1065.84	33.77	1007
1976	1278.51	40.51	1208
1977	1587.45	50.30	1500
1978	1050.27	33.28	993
1979	1237.73	39.22	1170
1980	1246.81	39.51	1178
1981	1515.30	48.02	1432
1982	1121.90	35.55	1060
1983	1466.68	46.48	1386
1984	1261.24	39.97	1192
1985	787.84	24.97	745
1986	998.02	31.63	943
1987	1082.68	34.31	1023
1988	1180.98	37.42	1116
1989	890.28	28.21	841
1990	1263.51	40.04	1194

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1991	1069.89	33.90	1011
1992	1144.49	36.27	1082
1993	1503.08	47.63	1421
1994	1229.29	38.95	1162
1995	1241.42	39.34	1173
1996	1260.68	39.95	1192
1997	1163.74	36.88	1100
1998	1326.95	42.05	1254
1999	1443.63	45.75	1364
2000	1395.25	44.21	1319
2001	881.06	27.92	833
Mean	1162.20	36.83	1098

Table B.2
Grey
Reference Inflow Sequence

Sequence Length: 52 years
Plants in Service: 1967 (Bay d'Espoir), 1983 (Upper Salmon)
Area (km^2) 2152

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1950	1702.96	53.96	791
1951	2218.62	70.30	1031
1952	2305.28	73.05	1071
1953	2138.21	67.76	994
1954	2470.36	78.28	1148
1955	1934.32	61.29	899
1956	2318.29	73.46	1077
1957	2037.39	64.56	947
1958	2354.26	74.60	1094
1959	1759.90	55.77	818
1960	1583.77	50.19	736
1961	1571.59	49.80	730
1962	2513.42	79.65	1168
1963	2558.43	81.07	1189
1964	2250.05	71.30	1046
1965	2134.23	67.63	992
1966	1782.25	56.48	828
1967	2285.45	72.42	1062
1968	2470.07	78.27	1148
1969	2741.91	86.89	1274
1970	1642.09	52.03	763
1971	2638.00	83.59	1226
1972	2927.13	92.76	1360
1973	2782.14	88.16	1293
1974	2710.19	85.88	1259
1975	2284.60	72.39	1062
1976	3050.85	96.68	1418
1977	3494.88	110.75	1624
1978	2416.84	76.59	1123
1979	2378.91	75.38	1105
1980	2527.00	80.08	1174
1981	3205.74	101.58	1490
1982	2532.99	80.27	1177
1983	3122.26	98.94	1451
1984	2692.44	85.32	1251
1985	1754.92	55.61	815
1986	2167.23	68.68	1007
1987	2058.90	65.24	957
1988	2292.97	72.66	1066
1989	1782.08	56.47	828
1990	2466.46	78.16	1146

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1991	2166.47	68.65	1007
1992	2223.24	70.45	1033
1993	2967.67	94.04	1379
1994	2411.18	76.41	1120
1995	2695.60	85.42	1253
1996	2545.78	80.67	1183
1997	2549.92	80.80	1185
1998	2415.36	76.54	1122
1999	3413.74	108.17	1586
2000	3488.51	110.54	1621
2001	2000.93	63.41	930
Mean	2402.65	76.14	1116

Table B.3
Upper Salmon
Reference Inflow Sequence

Sequence Length: 52 years
Plants in Service: 1967 (Bay d'Espoir), 1983 (Upper Salmon)
Area (km^2) 902

Year	Volume $10^6\ m^3$	Flow m^3/s	Runoff mm
1950	609.66	19.32	676
1951	888.01	28.14	984
1952	970.69	30.76	1076
1953	852.62	27.02	945
1954	1014.31	32.14	1125
1955	792.01	25.10	878
1956	959.09	30.39	1063
1957	761.45	24.13	844
1958	884.04	28.01	980
1959	683.87	21.67	758
1960	620.13	19.65	688
1961	585.61	18.56	649
1962	1082.56	34.30	1200
1963	1102.93	34.95	1223
1964	957.39	30.34	1061
1965	890.00	28.20	987
1966	727.75	23.06	807
1967	903.88	28.64	1002
1968	915.77	29.02	1015
1969	997.04	31.59	1105
1970	928.22	29.41	1029
1971	954.57	30.25	1058
1972	851.76	26.99	944
1973	769.93	24.40	854
1974	668.57	21.19	741
1975	650.15	20.60	721
1976	839.86	26.61	931
1977	806.19	25.55	894
1978	524.15	16.61	581
1979	639.68	20.27	709
1980	904.45	28.66	1003
1981	918.89	29.12	1019
1982	740.20	23.46	821
1983	901.60	28.57	1000
1984	936.72	29.68	1038
1985	752.93	23.86	835
1986	751.24	23.81	833
1987	647.10	20.51	717
1988	1061.87	33.65	1177
1989	823.42	26.09	913
1990	861.69	27.31	955
1991	987.82	31.30	1095
1992	1144.45	36.27	1269
1993	1250.35	39.62	1386
1994	1035.17	32.80	1148
1995	749.77	23.76	831
1996	844.04	26.75	936
1997	896.41	28.41	994
1998	1041.85	33.01	1155
1999	608.40	19.28	675
2000	516.38	16.36	572
2001	538.66	17.07	597
Mean	841.26	26.66	933

Table B.4
Lower Salmon
Reference Inflow Sequence

Sequence Length: 52 years
Plants in Service: 1967 (Bay d'Espoir), 1983 (Upper Salmon)
Area (km^2) 1792

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1950	1210.83	38.37	676
1951	1762.45	55.85	984
1952	1925.83	61.03	1075
1953	1691.37	53.60	944
1954	2013.62	63.81	1124
1955	1573.00	49.85	878
1956	1904.32	60.34	1063
1957	1512.39	47.92	844
1958	1754.51	55.60	979
1959	1362.31	43.17	760
1960	1229.24	38.95	686
1961	1161.83	36.82	648
1962	2151.25	68.17	1200
1963	2190.32	69.41	1222
1964	1901.47	60.25	1061
1965	1767.25	56.00	986
1966	1445.57	45.81	807
1967	1794.16	56.85	1001
1968	1816.83	57.57	1014
1969	1979.35	62.72	1105
1970	1843.71	58.42	1029
1971	1895.24	60.06	1058
1972	1690.51	53.57	943
1973	1529.67	48.47	854
1974	1328.05	42.08	741
1975	1290.67	40.90	720
1976	1668.72	52.88	931
1977	1600.47	50.72	893
1978	1042.05	33.02	582
1979	1269.46	40.23	708
1980	1794.99	56.88	1002
1981	1823.61	57.79	1018
1982	1468.80	46.54	820
1983	2098.27	66.49	1171
1984	1984.45	62.88	1107
1985	1244.52	39.44	694
1986	1487.21	47.13	830
1987	1362.02	43.16	760
1988	1620.14	51.34	904
1989	1232.67	39.06	688
1990	1780.05	56.41	993

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1991	1502.94	47.63	839
1992	1605.63	50.88	896
1993	2269.43	71.91	1266
1994	1725.70	54.68	963
1995	1995.24	63.23	1113
1996	1834.16	58.12	1024
1997	1735.23	54.99	968
1998	1887.41	59.81	1053
1999	2112.17	66.93	1179
2000	2220.61	70.37	1239
2001	1353.00	42.87	755
Mean	1681.63	53.29	938

Table B.5
Cat Arm
Reference Inflow Sequence

Sequence Length: 72 years
Plant in Service: 1985
Area (km^2) 632

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1930	1031.06	32.67	1631
1931	809.36	25.65	1281
1932	912.53	28.92	1444
1933	1293.19	40.98	2046
1934	982.03	31.12	1554
1935	1038.51	32.91	1643
1936	874.86	27.72	1384
1937	859.22	27.23	1360
1938	689.62	21.85	1091
1939	1125.21	35.66	1780
1940	853.81	27.06	1351
1941	1013.44	32.11	1604
1942	975.69	30.92	1544
1943	818.24	25.93	1295
1944	979.38	31.03	1550
1945	1088.71	34.50	1723
1946	859.08	27.22	1359
1947	844.30	26.75	1336
1948	785.74	24.90	1243
1949	1000.91	31.72	1584
1950	779.70	24.71	1234
1951	827.05	26.21	1309
1952	889.70	28.19	1408
1953	736.76	23.35	1166
1954	766.23	24.28	1212
1955	549.04	17.40	869
1956	722.89	22.91	1144
1957	733.93	23.26	1161
1958	627.04	19.87	992
1959	690.00	21.86	1092
1960	669.87	21.23	1060
1961	662.93	21.01	1049
1962	833.04	26.40	1318
1963	841.57	26.67	1332
1964	841.08	26.65	1331
1965	735.49	23.31	1164
1966	782.79	24.81	1239
1967	712.59	22.58	1128
1968	720.87	22.84	1141
1969	1016.45	32.21	1608
1970	619.25	19.62	980

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1971	887.01	28.11	1403
1972	860.84	27.28	1362
1973	863.62	27.37	1366
1974	668.02	21.17	1057
1975	756.52	23.97	1197
1976	851.90	27.00	1348
1977	1158.97	36.73	1834
1978	779.91	24.71	1234
1979	1029.07	32.61	1628
1980	1026.23	32.52	1624
1981	967.29	30.65	1531
1982	940.55	29.80	1488
1983	581.16	18.42	920
1984	815.95	25.86	1291
1985	718.68	22.77	1137
1986	671.34	21.27	1062
1987	773.29	24.50	1224
1988	855.96	27.12	1354
1989	693.69	21.98	1098
1990	808.87	25.63	1280
1991	783.14	24.82	1239
1992	705.95	22.37	1117
1993	837.17	26.53	1325
1994	946.99	30.01	1498
1995	853.64	27.05	1351
1996	837.43	26.54	1325
1997	761.63	24.13	1205
1998	848.68	26.89	1343
1999	944.47	29.93	1494
2000	949.04	30.07	1502
2001	707.06	22.41	1119
Mean	839.96	26.62	1329

Table B.6
Hinds Lake
Reference Inflow Sequence

Sequence Length: 75 years
Plant in Service: 1980
Area (km^2) 651.1

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1927	806.90	25.57	1239
1928	598.38	18.96	919
1929	690.38	21.88	1060
1930	661.85	20.97	1017
1931	613.57	19.44	942
1932	653.95	20.72	1004
1933	836.40	26.50	1285
1934	668.59	21.19	1027
1935	769.63	24.39	1182
1936	598.13	18.95	919
1937	552.23	17.50	848
1938	509.00	16.13	782
1939	688.70	21.82	1058
1940	570.17	18.07	876
1941	713.93	22.62	1096
1942	685.11	21.71	1052
1943	558.90	17.71	858
1944	793.75	25.15	1219
1945	724.56	22.96	1113
1946	496.01	15.72	762
1947	564.65	17.89	867
1948	551.74	17.48	847
1949	790.94	25.06	1215
1950	491.13	15.56	754
1951	662.89	21.01	1018
1952	649.28	20.57	997
1953	593.26	18.80	911
1954	676.97	21.45	1040
1955	599.42	18.99	921
1956	654.60	20.74	1005
1957	576.92	18.28	886
1958	625.42	19.82	961
1959	531.39	16.84	816
1960	500.54	15.86	769
1961	490.81	15.55	754
1962	692.60	21.95	1064
1963	649.93	20.60	998
1964	630.18	19.97	968
1965	595.45	18.87	915
1966	481.81	15.27	740
1967	578.74	18.34	889

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1968	630.34	19.97	968
1969	760.27	24.09	1168
1970	627.59	19.89	964
1971	727.42	23.05	1117
1972	767.72	24.33	1179
1973	741.69	23.50	1139
1974	621.90	19.71	955
1975	618.65	19.60	950
1976	691.95	21.93	1063
1977	833.31	26.41	1280
1978	547.21	17.34	840
1979	601.06	19.05	923
1980	713.47	22.61	1096
1981	775.30	24.57	1191
1982	711.86	22.56	1093
1983	736.21	23.33	1131
1984	658.70	20.87	1012
1985	493.03	15.62	757
1986	536.99	17.02	825
1987	554.61	17.57	852
1988	675.10	21.39	1037
1989	488.88	15.49	751
1990	662.00	20.98	1017
1991	617.22	19.56	948
1992	613.22	19.43	942
1993	762.03	24.15	1170
1994	785.58	24.89	1207
1995	759.66	24.07	1167
1996	710.81	22.52	1092
1997	719.74	22.81	1105
1998	843.97	26.74	1296
1999	692.66	21.95	1064
2000	741.94	23.51	1140
2001	575.18	18.23	883
Mean	650.35	20.61	999

Table B.7
Paradise River
Reference Inflow Sequence

Sequence Length: 49 years
Plant in Service: 1989
Area (km^2) 476.5

Year	Volume 10^6 m^3	Flow m^3/s	Runoff mm
1953	519.54	16.46	1090
1954	569.80	18.06	1196
1955	592.85	18.79	1244
1956	605.80	19.20	1271
1957	504.01	15.97	1058
1958	482.94	15.30	1014
1959	466.62	14.79	979
1960	395.51	12.53	830
1961	353.28	11.19	741
1962	663.22	21.02	1392
1963	643.50	20.39	1350
1964	529.91	16.79	1112
1965	478.84	15.17	1005
1966	472.86	14.98	992
1967	519.60	16.47	1090
1968	594.96	18.85	1249
1969	596.79	18.91	1252
1970	612.70	19.42	1286
1971	581.88	18.44	1221
1972	486.67	15.42	1021
1973	617.54	19.57	1296
1974	475.04	15.05	997
1975	449.70	14.25	944
1976	519.32	16.46	1090
1977	487.72	15.45	1024
1978	465.54	14.75	977
1979	473.46	15.00	994
1980	711.41	22.54	1493
1981	693.32	21.97	1455
1982	541.97	17.17	1137
1983	616.25	19.53	1293
1984	655.57	20.77	1376
1985	403.19	12.78	846
1986	533.02	16.89	1119
1987	450.81	14.29	946
1988	672.04	21.30	1410
1989	384.39	12.18	807
1990	613.82	19.45	1288
1991	446.74	14.16	938
1992	456.85	14.48	959
1993	654.20	20.73	1373
1994	508.56	16.12	1067
1995	561.95	17.81	1179
1996	468.55	14.85	983
1997	463.10	14.67	972
1998	519.06	16.45	1089
1999	519.68	16.47	1091
2000	521.27	16.52	1094
2001	467.68	14.82	981
Mean	531.08	16.83	1115

Appendix C

Environment Canada Streamflow

Table C.1
Bay du Nord River at Big Falls
Streamflow Record

ID Number: 02ZF001
Record Count: 49
Area (km^2) 1170

Year	Flow m^3/s	Runoff mm
1952	44.7	1206
1953	39.5	1065
1954	44.7	1206
1955	37.1	1001
1956	46.3	1249
1957	35.5	958
1958	35.9	968
1959	37.1	1001
1960	25.6	690
1961	24.1	650
1962	43.9	1184
1963	45.6	1230
1964	40.0	1079
1965	39.3	1060
1966	31.4	847
1967	39.3	1060
1968	46.6	1257
1969	44.9	1211
1970	42.2	1138
1971	45.5	1227
1972	44.7	1206
1973	47.9	1292
1974	35.4	955
1975	34.8	939
1976	47.2	1273
1977	42.2	1138
1978	37.2	1003
1979	34.3	925
1981	50.2	1354
1982	37.2	1003
1983	51.8	1397
1984	48.2	1300
1985	28.5	769
1986	37.2	1003
1987	33.9	914
1988	44.3	1195
1989	31.1	839
1990	44.4	1198
1991	36.8	993
1992	37.4	1009
1993	52.4	1413

Year	Flow m^3/s	Runoff mm
1994	43.1	1163
1995	43.8	1181
1996	36.7	990
1997	36.8	993
1998	37.0	998
1999	44.2	1192
2000	42.0	1133
2001	33.0	889
Mean	40.1	1080

Table C.2
Gander River at Big Chute
Streamflow Record

ID Number: 02YQ001
Record Count: 52
Area (km^2) 4450

Year	Flow m^3/s	Runoff mm
1950	78.7	558
1951	114	808
1952	123	872
1953	112	794
1954	132	936
1955	117	830
1956	124	879
1957	111	787
1958	102	723
1959	91.5	649
1960	95.4	677
1961	71.4	506
1962	158.0	1120
1963	142	1007
1964	129	915
1965	121	858
1966	106	752
1967	110	780
1968	132	936
1969	134	950
1970	142	1007
1971	119	844
1972	121	858
1973	139	986
1974	116	823
1975	104	738
1976	129	915
1977	128	908
1978	93.3	662
1979	120	851
1980	142	1007
1981	146	1035
1982	105	745
1983	131	929
1984	155	1099
1985	82.1	582
1986	105	745
1987	98.3	697
1988	118	837
1989	85.6	607
1990	119	844
1991	130	922
1992	125	886
1993	148	1050
1994	138	979
1995	137	972
1996	124	879
1997	118	837
1998	121	858
1999	129	915
2000	127	901
2001	100	712
Mean	119.2	845

Table C.3
Garnish River near Garnish
Streamflow Record

ID Number: 02ZG001
Record Count: 43
Area (km^2) 205

Year	Flow m^3/s	Runoff mm
1959	8.34	1284
1960	5.19	799
1961	6.76	1041
1962	8.07	1242
1963	9.45	1455
1964	8.66	1333
1965	7.79	1199
1966	7.61	1171
1967	7.58	1167
1968	9.62	1481
1969	9.93	1529
1970	9.88	1521
1971	8.64	1330
1972	8.37	1288
1973	10.0	1539
1974	9.39	1445
1975	8.57	1319
1976	8.41	1295
1977	7.97	1227
1978	8.55	1316
1979	9.16	1410
1980	10.7	1647
1981	10.4	1601
1982	10.4	1601
1983	10.4	1601
1984	9.06	1395
1985	7.52	1158
1986	9.99	1538
1987	7.95	1224
1988	11.3	1740
1989	8.30	1278
1990	9.24	1422
1991	8.16	1256
1992	7.76	1195
1993	9.71	1495
1994	10.9	1678
1995	9.59	1476
1996	8.24	1268
1997	9.17	1412
1998	10.7	1647
1999	8.62	1327

Year	Flow m^3/s	Runoff mm
2000	8.80	1355
2001	8.49	1307
Mean	8.91	1372

Table C.4
Harrys River below Highway Bridge
Streamflow Record

ID Number: 02YJ001
Record Count: 33
Area (km^2) 640

Year	Flow m^3/s	Runoff mm
1969	23.2	1144
1970	21.1	1040
1971	24.5	1208
1972	32.0	1578
1973	31.9	1573
1974	27.5	1356
1975	26.1	1287
1976	25.4	1252
1977	31.4	1548
1978	25.2	1243
1979	29.3	1445
1980	25.0	1233
1981	26.4	1302
1982	30.8	1519
1983	26.6	1312
1984	26.7	1317
1985	21.7	1070
1986	19.1	942
1987	22.1	1090
1988	24.2	1193
1989	26.0	1282
1990	34.6	1706
1991	25.3	1248
1992	22.8	1124
1993	32.8	1617
1994	32.5	1603
1995	25.8	1272
1996	23.6	1164
1997	25.1	1238
1998	27.9	1376
1999	27.8	1371
2000	31.7	1563
2001	20.8	1024
Mean	26.6	1310

Table C.5
Isle aux Morts River below Highway Bridge
Streamflow Record

ID Number: 02ZB001
Record Count: 39
Area (km^2) 205

Year	Flow m^3/s	Runoff mm
1963	12.1	1863
1964	13.1	2017
1965	13.6	2094
1966	13.6	2094
1967	15.3	2355
1968	15.4	2371
1969	15.7	2417
1970	11.6	1786
1971	14.1	2171
1972	16.4	2525
1973	14.1	2171
1974	12.5	1924
1975	10.7	1647
1976	13.4	2063
1977	15.7	2417
1978	12.7	1955
1979	14.8	2278
1980	12.2	1878
1981	15.3	2355
1982	15.8	2432
1983	15.2	2340
1984	13.3	2047
1985	11.9	1832
1986	10.3	1586
1987	11.8	1816
1988	13.4	2063
1989	11.9	1832
1990	16.8	2586
1991	10.4	1601
1992	10.4	1601
1993	14.7	2263
1994	16.0	2463
1995	13.4	2063
1996	16.5	2540
1997	14.5	2232
1998	18.3	2817
1999	15.8	2432
2000	14.0	2155
2001	10.1	1552
Mean	13.8	2119

Table C.6
Lewaseechjeech Brook at Little Grand Lake
Streamflow Record

ID Number: 02YK002
Record Count: 39
Area (km^2) 470

Year	Flow m^3/s	Runoff mm
1956	17.0	1141
1957	18.2	1222
1958	20.0	1343
1959	14.7	987
1960	13.1	880
1961	13.5	906
1962	18.2	1222
1963	17.8	1195
1964	16.7	1121
1965	14.8	994
1966	14.0	940
1973	19.3	1296
1974	17.5	1175
1975	17.0	1141
1976	16.6	1115
1977	23.0	1544
1978	15.1	1014
1979	18.4	1235
1980	19.0	1276
1982	20.7	1390
1983	21.4	1437
1984	19.9	1336
1985	13.6	913
1986	16.4	1101
1987	14.8	994
1988	19.2	1289
1989	16.8	1128
1990	20.0	1343
1991	17.1	1148
1992	17.0	1141
1993	22.6	1517
1994	19.0	1276
1995	19.8	1329
1996	18.6	1249
1997	19.3	1296
1998	21.4	1437
1999	21.7	1457
2000	21.2	1423
2001	14.7	985
Mean	17.9	1204

Table C.7
Middle Brook near Gambo
Streamflow Record

ID Number: 02YR001
Record Count: 42
Area (km^2) 275

Year	Flow m^3/s	Runoff mm
1960	6.69	768
1961	4.66	535
1962	9.42	1081
1963	7.12	817
1964	6.71	770
1965	6.85	786
1966	6.54	750
1967	5.74	659
1968	7.32	840
1969	7.79	894
1970	8.18	939
1971	6.64	762
1972	6.63	761
1973	7.88	904
1974	6.81	781
1975	6.56	753
1976	6.17	708
1977	6.41	736
1978	4.37	501
1979	7.24	831
1980	8.81	1011
1981	8.13	933
1982	6.12	702
1983	6.28	721
1984	8.13	933
1985	4.24	487
1986	5.34	613
1987	5.47	628
1988	6.41	736
1989	4.20	482
1990	6.80	780
1991	7.00	803
1992	7.33	841
1993	7.94	911
1994	7.38	847
1995	7.31	839
1996	6.25	717
1997	6.02	691
1998	7.21	827
1999	7.02	806
2000	6.29	722

Year	Flow m^3/s	Runoff mm
2001	5.97	685
Mean	6.70	769

Table C.8
Pipers Hole River at Mothers Brook
Streamflow Record

ID Number: 02ZH001
Record Count: 49
Area (km^2) 764

Year	Flow m^3/s	Runoff mm
1953	24.0	991
1954	26.3	1086
1955	27.4	1132
1956	28.0	1157
1957	23.3	962
1958	22.1	913
1959	21.6	892
1960	18.3	756
1961	16.3	673
1962	30.8	1272
1963	29.7	1227
1964	24.5	1012
1965	22.2	917
1966	21.9	905
1967	24.0	991
1968	27.5	1136
1969	27.6	1140
1970	28.3	1169
1971	27.0	1115
1972	22.5	929
1973	28.6	1181
1974	21.8	900
1975	20.8	859
1976	24.0	991
1977	22.6	934
1978	21.5	888
1979	21.9	905
1980	32.8	1355
1981	31.9	1318
1982	25.1	1037
1983	28.4	1173
1984	29.9	1235
1985	18.5	764
1986	24.6	1016
1987	20.8	859
1988	31.2	1289
1989	17.0	702
1990	26.5	1095
1991	25.1	1037
1992	22.3	921
1993	35.1	1450

Year	Flow m^3/s	Runoff mm
1994	25.2	1041
1995	28.9	1194
1996	29.1	1202
1997	21.3	880
1998	24.8	1024
1999	29.9	1235
2000	28.2	1165
2001	23.0	949
Mean	25.2	1040

Table C.9
Rocky River near Colinet
Streamflow Record

ID Number: 02ZK001
Record Count: 52
Area (km^2) 301

Year	Flow m^3/s	Runoff mm
1950	9.06	950
1951	11.6	1216
1952	11.8	1237
1953	11.8	1237
1954	11.5	1206
1955	13.5	1415
1956	13.5	1415
1957	11.9	1248
1958	9.80	1027
1959	9.80	1027
1960	7.99	838
1961	7.02	736
1962	11.9	1248
1963	9.08	952
1964	12.4	1300
1965	8.92	935
1966	11.0	1153
1967	9.65	1012
1968	10.7	1122
1969	12.8	1342
1970	15.4	1615
1971	12.7	1332
1972	11.8	1237
1973	12.1	1269
1974	12.3	1290
1975	10.3	1080
1976	12.2	1279
1977	8.28	868
1978	12.3	1290
1979	10.9	1143
1980	14.9	1562
1981	12.9	1352
1982	10.9	1143
1983	12.0	1258
1984	11.3	1185
1985	9.50	996
1986	12.3	1290
1987	9.32	977
1988	10.7	1122
1989	10.4	1090
1990	12.3	1290

Year	Flow m^3/s	Runoff mm
1991	11.3	1185
1992	11.9	1248
1993	13.2	1384
1994	12.3	1290
1995	11.2	1174
1996	10.2	1069
1997	10.2	1069
1998	10.1	1059
1999	11.0	1153
2000	11.2	1174
2001	10.6	1108
Mean	11.2	1177

Table C.10
Streamflow Record

ID Number: 02YS003
Record Count: 34
Area (km^2) 36.7

Year	Flow m^3/s	Runoff mm
1968	1.17	1006
1969	1.29	1109
1970	1.37	1178
1971	1.05	903
1972	1.11	954
1973	1.12	963
1974	0.954	820
1975	0.928	798
1976	0.866	745
1977	0.878	755
1978	0.804	691
1979	1.07	920
1980	1.29	1109
1981	1.29	1109
1982	1.07	920
1983	1.01	868
1984	1.17	1006
1985	0.695	598
1986	0.952	819
1987	0.888	764
1988	1.10	946
1989	0.542	466
1990	1.20	1032
1991	1.09	937
1992	0.945	813
1993	1.18	1015
1994	1.02	877
1995	1.14	980
1996	0.986	848
1997	0.966	831
1998	0.962	827
1999	1.23	1058
2000	1.02	877
2001	0.998	859
Mean	1.04	894

Table C.11
Torrent River at Bristol's Pool
Streamflow Record

ID Number: 02YC001
Record Count: 42
Area (km^2) 624

Year	Flow m^3/s	Runoff mm
1960	23.2	1173
1961	21.0	1062
1962	23.4	1183
1963	25.4	1285
1964	27.3	1381
1965	25.6	1295
1966	25.4	1285
1967	25.5	1290
1968	22.4	1133
1969	31.3	1583
1970	22.7	1148
1971	29.5	1492
1972	29.6	1497
1973	27.4	1386
1974	24.0	1214
1975	21.1	1067
1976	24.8	1254
1977	35.0	1770
1978	26.4	1335
1979	32.8	1659
1980	29.6	1497
1981	24.8	1254
1982	27.1	1371
1983	22.6	1143
1984	27.2	1376
1985	24.4	1234
1986	17.4	880
1987	22.5	1138
1988	23.4	1183
1989	23.8	1204
1990	26.4	1335
1991	20.5	1037
1992	18.7	946
1993	22.0	1113
1994	25.1	1269
1995	23.0	1163
1996	21.1	1067
1997	22.3	1128
1998	22.3	1128
1999	25.4	1285
2000	22.0	1113

Year	Flow m^3/s	Runoff mm
2001	20.3	1029
Mean	24.7	1247

Table C.12
Upper Humber River near Reidville
Streamflow Record

ID Number: 02YL001
Record Count: 62
Area (km^2) 2110

Year	Flow m^3/s	Runoff mm
1930	103	1540
1931	86.1	1288
1938	74.9	1120
1939	108	1615
1940	80.3	1201
1941	101	1511
1942	95.5	1428
1943	87.4	1307
1944	98.5	1473
1945	104	1555
1946	84.3	1261
1947	80.8	1208
1948	73.6	1101
1953	74.2	1110
1954	90.1	1348
1955	62.8	939
1956	75.0	1122
1957	77.1	1153
1958	71.7	1072
1959	71.6	1071
1960	61.0	912
1961	72.2	1080
1962	88.9	1330
1963	88.6	1325
1964	79.8	1194
1965	75.5	1129
1966	77.5	1159
1967	69.6	1041
1968	75.0	1122
1969	96.3	1440
1970	69.6	1041
1971	77.4	1158
1972	94.1	1407
1973	91.4	1367
1974	73.0	1092
1975	75.7	1132
1976	91.6	1370
1977	111	1660
1978	76.3	1141
1979	85.3	1276
1980	92.5	1383
1981	88.2	1319
1982	92.8	1388
1983	76.5	1144
1984	86.2	1289
1985	68.5	1025
1986	64.3	962
1987	68.1	1019
1988	83.3	1246
1989	63.2	945
1990	86.6	1295
1991	72.6	1086
1992	66.4	993
1993	86.4	1292
1994	93.2	1394
1995	85.2	1274
1996	74.2	1110
1997	76.5	1144
1998	79.7	1192
1999	92.0	1376
2000	88.0	1316
2001	65.4	978
Mean	81.9	1225

Appendix D

Environment Canada Precipitation

Table D.1
Colinet
Precipitation Record

ID Number: 8401200
Record Count: 37

Year	mm
1939	1536.2
1940	1482.0
1941	1522.8
1942	1447.6
1949	1365.9
1952	1397.9
1954	1389.8
1957	1321.8
1958	1557.7
1960	1222.4
1961	1001.0
1962	1571.9
1963	1287.9
1966	1471.8
1967	1313.9
1968	1373.5
1969	1529.3
1970	1665.9
1971	1374.2
1973	1452.4
1974	1522.8
1975	1261.5
1976	1527.1
1977	1197.4
1978	1394.7
1979	1271.0
1980	1778.5
1981	1484.4
1982	1371.7
1983	1459.5
1984	1436.0
1985	1107.8
1986	1104.1
1988	1421.7
1989	1321.6
1990	1560.9
1991	1465.6
Mean	1404.7

Table D.2
Corner Brook
Precipitation Record

ID Number: 8401300
Record Count: 58

Year	mm
1934	1038.1
1936	1165.3
1938	1138.5
1939	1302.2
1940	1106.5
1941	1093.2
1944	1365.0
1945	1176.3
1946	1199.4
1947	1075.3
1948	1110.7
1949	1189.1
1950	1025.8
1951	1263.6
1953	1005.1
1954	1077.9
1955	1311.5
1956	1117.0
1957	1234.9
1958	1191.6
1959	913.0
1960	956.1
1961	1030.0
1962	1172.6
1963	1215.1
1964	1048.0
1965	1008.0
1966	865.7
1967	995.2
1968	1145.0
1969	933.7
1970	1186.4
1971	1102.1
1972	1296.5
1973	1196.8
1974	1086.1
1975	1191.1
1976	1367.0
1977	1283.7
1978	1216.3
1979	1259.9
1980	1304.9

Year	mm
1981	1289.3
1982	1404.7
1983	1330.9
1984	1331.7
1985	1057.3
1986	1154.7
1987	1053.4
1988	1313.0
1989	1216.3
1990	1421.8
1991	1179.1
1992	1106.1
1993	1320.9
1994	1408.0
1998	1408.1
1999	1342.6
Mean	1177.6

Table D.3
Daniel's Harbour
Precipitation Record

ID Number: 8401400
Record Count: 30

Year	mm
1949	1006.8
1953	1061.6
1963	1011.8
1964	1045.9
1965	1243.7
1966	933.9
1967	1273.7
1968	1200.5
1969	957.6
1970	1102.1
1971	1271.7
1972	1243.6
1973	1145.9
1974	1150.9
1975	976.9
1976	1177.9
1978	1231.4
1979	1390.9
1980	1336.5
1981	1181.8
1982	1391.0
1983	1273.3
1985	809.4
1986	754.4
1987	847.3
1989	1153.1
1990	1460.4
1991	1060.8
1992	1082.7
1994	1330.4
Mean	1136.9

Table D.4
Deer Lake
Precipitation Record

ID Number: 8401500
Record Count: 44

Year	mm
1934	740.3
1935	870.5
1938	762.0
1940	802.5
1941	931.1
1943	759.9
1944	1267.7
1946	1017.5
1947	650.5
1948	799.3
1949	946.1
1951	1206.9
1954	1096.7
1957	1077.1
1958	1061.6
1959	869.7
1962	1211.3
1963	1081.9
1966	809.8
1967	1060.9
1972	1031.1
1973	1025.9
1976	1059.4
1978	936.8
1979	1149.8
1980	1239.1
1981	1193.1
1982	1329.7
1983	1302.9
1984	1260.3
1985	928.2
1986	1014.2
1987	933.0
1988	1171.4
1989	914.2
1990	1173.5
1991	1095.2
1992	982.1
1993	1191.9
1994	1285.5
1995	1352.5
1996	1161.2

Year	mm
1998	1240.4
1999	1265.5
Mean	1051.4

Table D.5
Exploits Dam
Precipitation Record

ID Number: 8401550
Record Count: 38

Year	mm
1957	1072.9
1958	1151.8
1959	888.6
1960	962.3
1964	1327.8
1965	1159.9
1966	1101.8
1967	1125.9
1970	1280.8
1971	1156.6
1972	1109.9
1973	1046.2
1974	956.0
1975	1069.3
1976	1086.3
1977	1090.0
1978	823.1
1979	1013.9
1980	1173.1
1981	1209.1
1982	1100.3
1983	1311.3
1984	1091.6
1985	917.4
1986	925.5
1987	904.8
1988	1157.1
1989	916.8
1990	1009.9
1991	1124.6
1992	945.8
1993	1206.5
1994	1236.8
1995	1174.3
1996	1053.1
1997	1089.8
1998	1176.7
1999	1091.0
Mean	1085.2

Table D.6
Gander International Airport
Precipitation Record

ID Number: 8401700
Record Count: 63

Year	mm
1937	980.6
1938	1166.2
1939	1055.6
1940	1035.2
1941	1071.4
1942	1016.9
1943	950.2
1944	1053.1
1945	917.5
1946	905.1
1947	861.2
1948	997.8
1949	1202.1
1950	817.3
1951	1078.8
1952	967.1
1953	972.5
1954	1069.6
1955	1208.7
1956	984.8
1957	1164.2
1958	1087.6
1959	908.9
1960	1097.7
1961	960.9
1962	1632.4
1963	1185.7
1964	1268.1
1965	1289.7
1966	1232.4
1967	945.2
1968	1172.8
1969	1160.1
1970	1207.2
1971	917.7
1972	1065.4
1973	1144.5
1974	1141.6
1975	1123.8
1976	1097.1
1977	1148.5
1978	984.4

Year	mm
1979	1279.1
1980	1436.5
1981	1348.3
1982	1194.3
1983	1191.7
1984	1340.3
1985	1018.9
1986	1188.9
1987	1082.0
1988	1408.3
1989	1071.1
1990	1211.3
1991	1208.5
1992	1296.3
1993	1310.1
1994	1300.7
1995	1425.4
1996	1184.2
1997	1114.0
1998	1243.2
1999	1236.8
Mean	1132.3

Table D.7
Grand Falls
Precipitation Record

ID Number: 8402050
Record Count: 40

Year	mm
1939	953.6
1944	1142.7
1945	824.5
1957	911.9
1958	969.4
1959	765.9
1960	873.8
1961	872.0
1962	1139.0
1964	1169.6
1965	1041.0
1966	976.1
1969	1049.3
1970	1032.1
1971	832.0
1972	876.3
1973	898.5
1974	955.6
1975	1013.3
1976	1131.1
1977	1071.3
1978	944.1
1979	1066.6
1980	1246.2
1981	1157.0
1982	1077.4
1983	1325.7
1984	1306.6
1985	891.8
1986	984.2
1987	904.7
1988	1131.6
1989	863.0
1990	987.1
1991	1198.5
1992	1137.1
1993	1279.2
1994	1258.7
1995	1110.9
1999	998.2
Mean	1034.2

Table D.8
Port aux Basques
Precipitation Record

ID Number: 8402975
Record Count: 54

Year	mm
1910	1673.0
1911	1370.2
1912	1623.8
1913	1393.2
1914	1358.8
1915	1523.6
1916	1328.1
1917	1321.3
1918	1438.3
1919	1480.6
1920	1135.2
1921	1232.2
1922	1436.3
1923	1309.0
1924	1252.9
1925	1691.1
1926	1549.4
1927	1457.3
1928	1469.6
1929	1512.2
1956	1407.8
1957	1109.3
1958	1585.0
1959	1262.2
1960	1160.5
1961	1186.5
1963	1203.5
1966	1407.5
1967	1460.2
1968	1708.5
1969	1611.3
1970	1440.9
1971	1567.3
1972	1579.9
1973	1572.6
1974	1476.3
1975	1366.1
1976	1459.7
1977	1629.4
1978	1249.1
1979	1748.5
1981	1485.6

Year	mm
1982	1620.2
1984	1440.4
1985	1410.8
1986	1284.2
1987	1519.3
1989	1599.4
1990	1812.8
1992	1342.9
1993	1761.5
1994	1756.6
1995	1472.4
1996	1782.0
Mean	1463.6

Table D.9
St. John's Airport
Precipitation Record

ID Number: 8403506
Record Count: 56

Year	mm
1942	1466.2
1943	1805.4
1944	1945.0
1945	1540.4
1946	1512.1
1947	1187.8
1948	1513.7
1949	1322.3
1950	1134.5
1951	1818.9
1952	1563.3
1953	1675.5
1954	1438.6
1955	2067.7
1956	1760.6
1957	1511.6
1958	1476.2
1959	1364.6
1960	1352.4
1961	1056.3
1962	1579.0
1963	1467.5
1964	1592.1
1965	1144.6
1966	1374.1
1967	1192.8
1968	1476.6
1969	1701.6
1970	1820.0
1971	1586.6
1972	1442.4
1973	1366.9
1974	1552.6
1975	1309.0
1976	1513.2
1977	1388.4
1978	1518.7
1979	1490.1
1980	1827.0
1981	1773.4
1982	1712.6
1983	1680.5

Year	mm
1984	1712.2
1985	1231.4
1986	1488.1
1987	1364.3
1988	1507.2
1989	1147.2
1990	1433.2
1991	1340.3
1992	1389.9
1993	1554.4
1994	1637.6
1995	1630.5
1998	1638.5
1999	1605.3
Mean	1512.6

Appendix E

Descriptive Statistics

Descriptive Statistics: Narural Flow Series (in mm)

Variable	N	Mean	Median	TrMean	StDev	SE Mean
Bay du Nord	49	1080.5	1065.0	1084.3	172.4	24.6
Gander	52	845.5	858.0	849.0	136.4	18.9
Lewaseechjeech	39	1203.5	1222.0	1202.5	177.2	28.4
Piper's Hole	49	1040.3	1024.0	1039.9	172.8	24.7
Rocky River	52	1176.9	1185.0	1177.5	170.9	23.7
Upper Humber	62	1225.3	1197.5	1220.4	175.0	22.2
Garnish River	43	1372.4	1333.0	1378.3	186.0	28.4
Harry's River	33	1310.3	1282.0	1308.7	193.7	33.7
Isle Aux Morts	39	2118.8	2094.0	2116.9	315.2	50.5
Middle Brook	42	768.8	769.0	769.2	130.9	20.2
South West	34	894.1	890.0	901.7	149.5	25.6
Torrent River	42	1247.3	1224.0	1240.3	183.8	28.4

Variable	Minimum	Maximum	Q1	Q3
Bay du Nord	650.0	1413.0	979.0	1206.0
Gander	506.0	1120.0	746.8	934.3
Lewaseechjeech	880.0	1544.0	1101.0	1336.0
Piper's Hole	673.0	1450.0	909.0	1171.0
Rocky River	736.0	1615.0	1069.0	1290.0
Upper Humber	912.0	1660.0	1098.8	1352.8
Garnish River	799.0	1740.0	1256.0	1521.0
Harry's River	942.0	1706.0	1178.5	1482.0
Isel Aux Morts	1552.0	2817.0	1863.0	2371.0
Middle Brook	482.0	1081.0	706.5	840.3
South West	466.0	1178.0	817.5	1006.0
Torrent River	880.0	1770.0	1128.0	1344.0

Descriptive Statistics: Precipitation Series (in mm)

Variable	N	Mean	Median	TrMean	StDev	SE Mean
Corner Brook	58	1177.6	1182.8	1179.8	136.0	17.9
Colinet	37	1404.7	1421.7	1406.7	156.8	25.8
Daniel's Harbour	30	1136.9	1152.0	1142.0	176.1	32.2
Deer Lake	44	1051.4	1061.3	1054.7	181.1	27.3
Exploits	38	1085.2	1091.3	1084.9	120.5	19.5
Grandfalls	40	1034.2	1022.7	1031.8	143.8	22.7
Port Aux Basque	54	1463.6	1460.0	1464.1	175.4	23.9
St. John's	56	1512.6	1511.9	1510.6	209.9	28.1
Gander	63	1132.3	1141.6	1127.4	155.8	19.6

Variable	Minimum	Maximum	Q1	Q3
Corner Brook	865.7	1421.8	1077.3	1297.9
Colinet	1001.0	1778.5	1317.8	1522.8
Daniel's Harbour	754.4	1460.4	1010.6	1272.1
Deer Lake	650.5	1352.5	928.9	1203.5
Exploits	823.1	1327.8	998.0	1163.2
Grandfalls	765.9	1325.7	906.5	1138.5
Port Aux Basque	1109.3	1812.8	1339.2	1588.6
St. John's	1056.3	2067.7	1368.7	1638.3
Gander	817.3	1632.4	1016.9	1211.3

Descriptive Statistics: Hydro's Reference Streamflow Sequences (all data)

Variable	N	Mean	Median	TrMean	StDev	SE Mean
Victoria	52	1098.4	1095.0	1097.2	181.8	25.2
Grey	52	1116.5	1112.5	1108.6	219.1	30.4
Upper Salmon	52	932.6	950.0	931.9	186.7	25.9
Lower Salmon	52	938.4	965.5	938.4	170.5	23.7
Hind's Lake	75	998.9	1004.0	997.3	145.2	16.8
Cat Arm	72	1329.1	1325.0	1321.1	223.5	26.3
Paradise	49	1114.5	1090.0	1113.7	178.1	25.4

Variable	Minimum	Maximum	Q1	Q3
Victoria	724.0	1500.0	1001.0	1193.5
Grey	730.0	1624.0	992.5	1244.8
Upper Salmon	572.0	1386.0	810.5	1060.3
Lower Salmon	582.0	1266.0	810.3	1060.3
Hind's Lake	740.0	1296.0	886.0	1105.0
Cat Arm	869.0	2046.0	1161.8	1492.5
Paradise	741.0	1493.0	982.0	1261.5

Descriptive Statistics: Hydro's Reference Streamflow Sequences - Using data from 1950 or later to 2001.

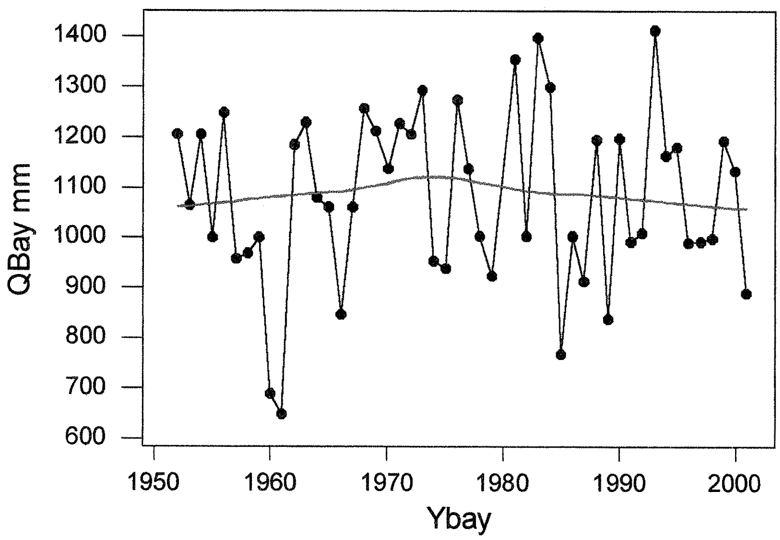
Variable	N	Mean	Median	TrMean	StDev	SE Mean
Victoria	52	1098.4	1095.0	1097.2	181.8	25.2
Grey	52	1116.5	1112.5	1108.6	219.1	30.4
Upper Salmon	52	932.6	950.0	931.9	186.7	25.9
Lower Salmon	52	938.4	965.5	938.4	170.5	23.7
Hind's Lake	52	994.8	997.5	993.5	142.9	19.8
Cat Arm	52	1267.2	1239.0	1261.7	193.6	26.9
Paradise	49	1114.5	1090.0	1113.7	178.1	25.4

Variable	Minimum	Maximum	Q1	Q3
Victoria	724.0	1500.0	1001.0	1193.5
Grey	730.0	1624.0	992.5	1244.8
Upper Salmon	572.0	1386.0	810.5	1060.3
Lower Salmon	582.0	1266.0	810.3	1060.3
Hind's Lake	740.0	1296.0	894.5	1102.8
Cat Arm	869.0	1834.0	1130.3	1360.0
Paradise	741.0	1493.0	982.0	1261.5

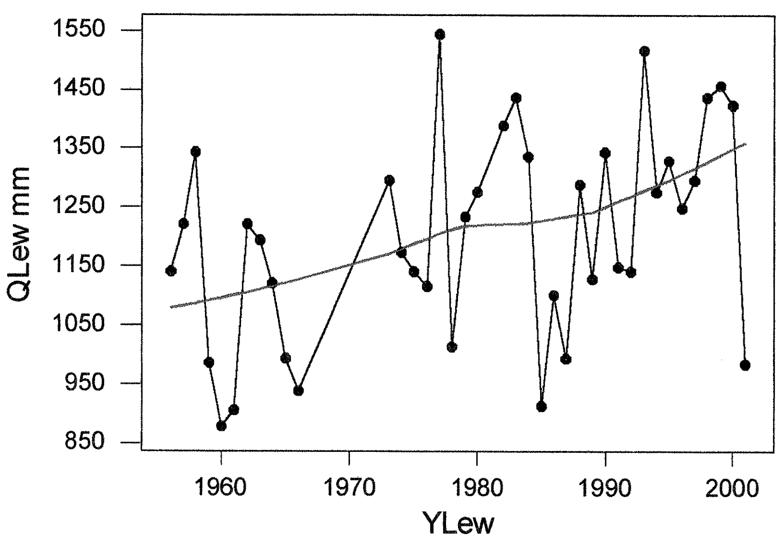
Appendix F

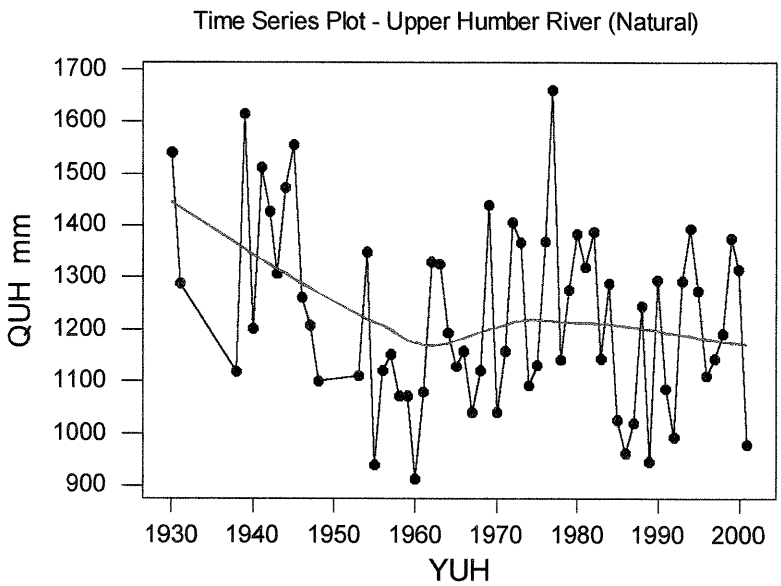
Time Series Plots

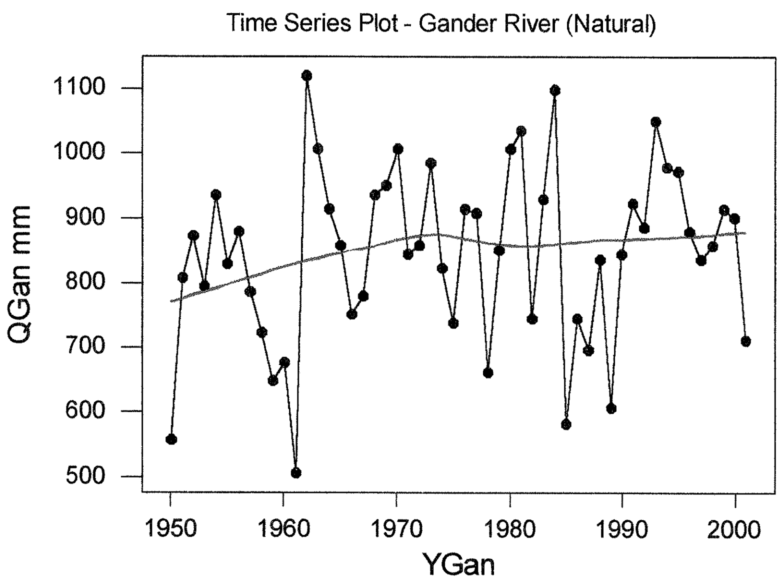
Time Series Plot - Bay Du Nord River (Natural)

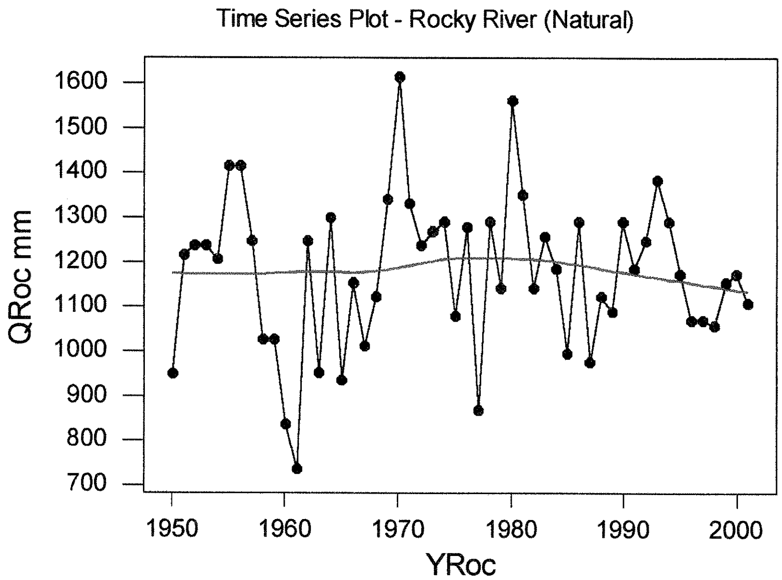


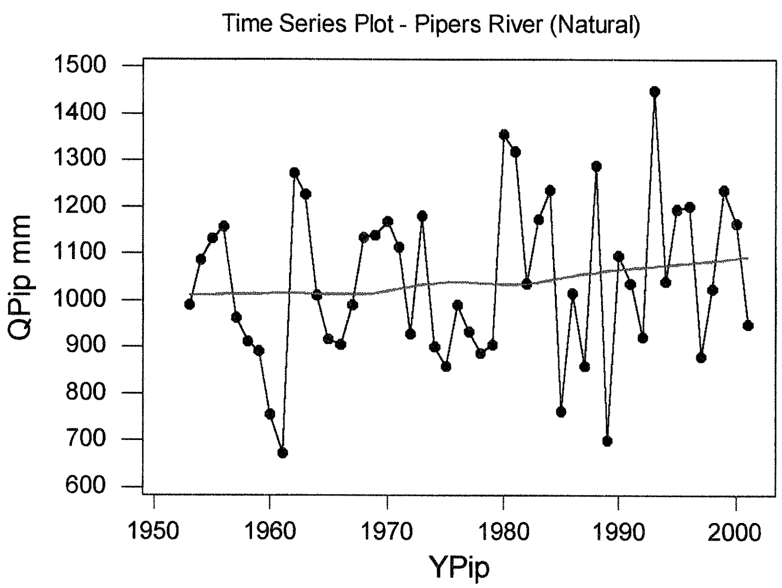
Time Series Plot - Leewaseechjeech Brook (Natural)



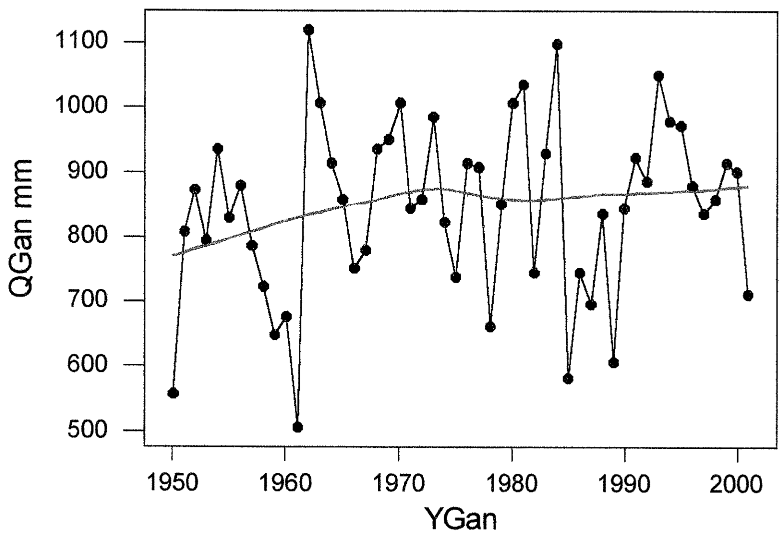

Time Series Plot - Upper Humber River (Natural)
QUH mm
YUH
1700
1600
1500
1400
1300
1200
1100
1000
900
1930
1940
1950
1960
1970
1980
1990
2000


Time Series Plot - Gander River (Natural)
QGan mm
YGan
1100
1000
900
800
700
600
500
1950
1960
1970
1980
1990
2000

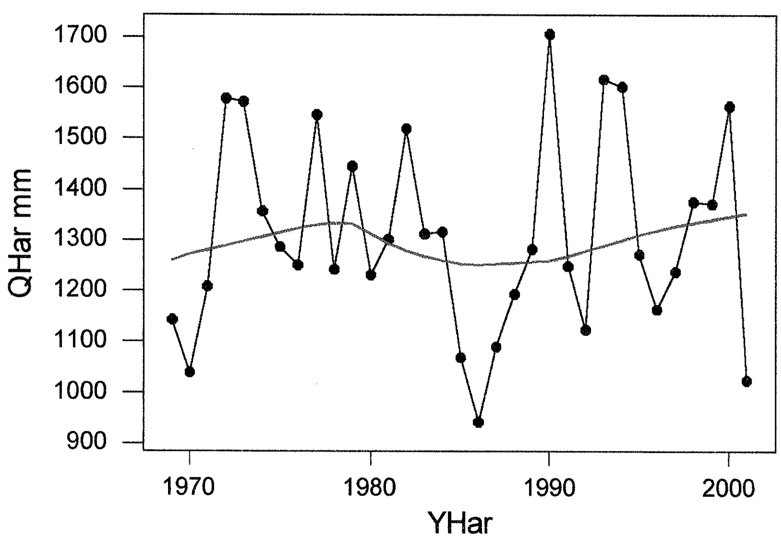

Time Series Plot - Rocky River (Natural)
QRoc mm
1600
1500
1400
1300
1200
1100
1000
900
800
700
1950
1960
1970
1980
1990
2000
YRoc

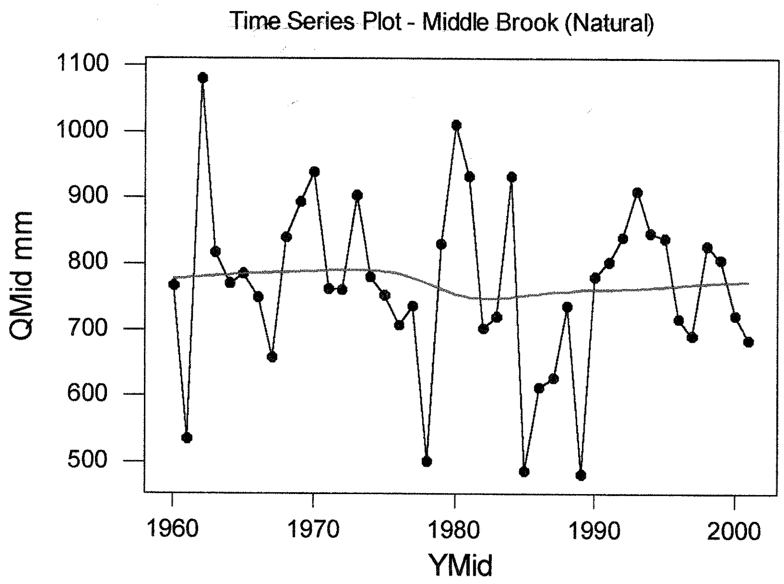

Time Series Plot - Pipers River (Natural)
QPip mm
1500
1400
1300
1200
1100
1000
900
800
700
600
1950
1960
1970
1980
1990
2000
YPip

Time Series Plot - Garnish River (Natural)

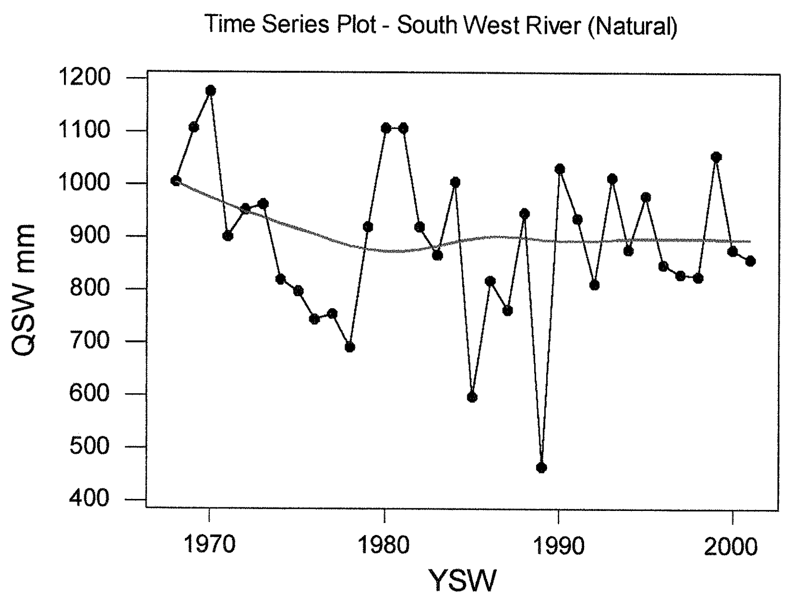


Time Series PLot - Harry's River (Natural)

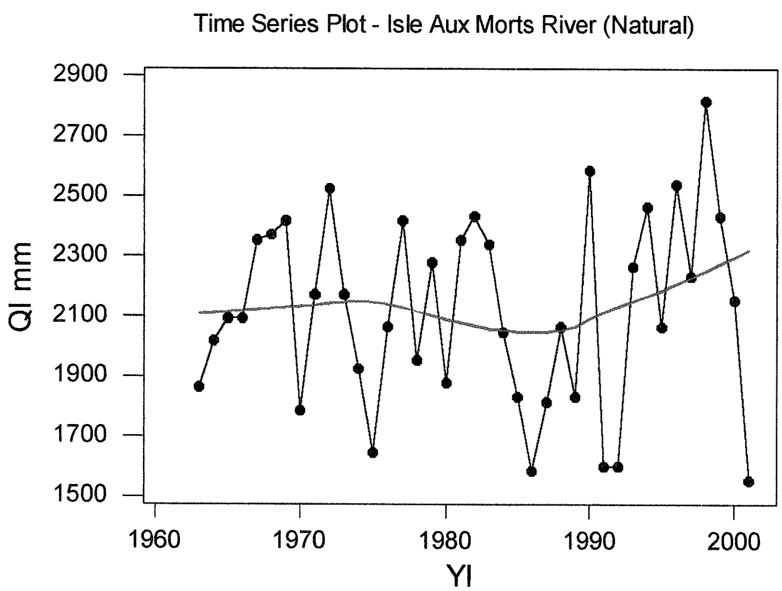


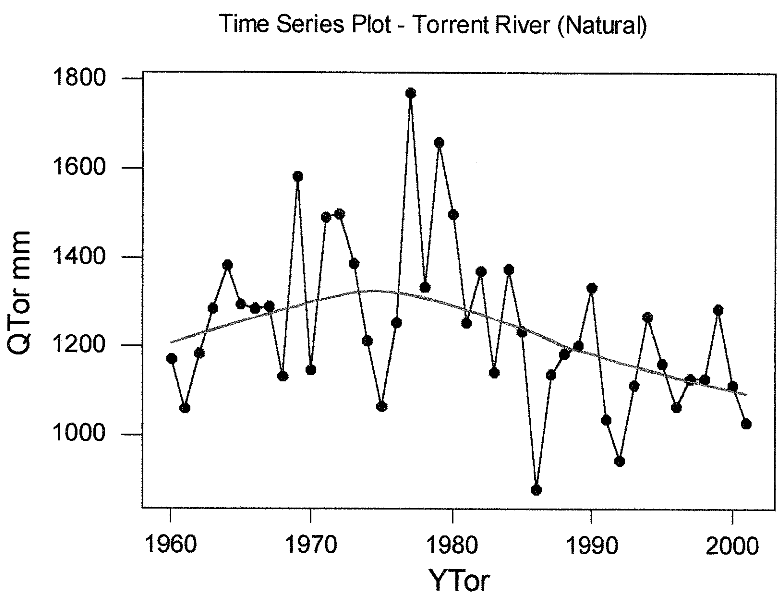


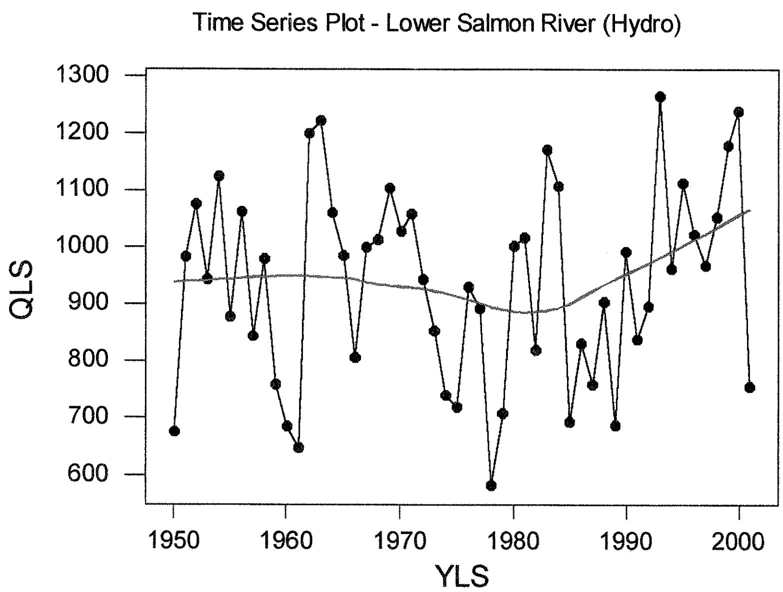
Time Series Plot - Middle Brook (Natural)
QMid mm
1100
1000
900
800
700
600
500
1960
1970
1980
1990
2000
YMid

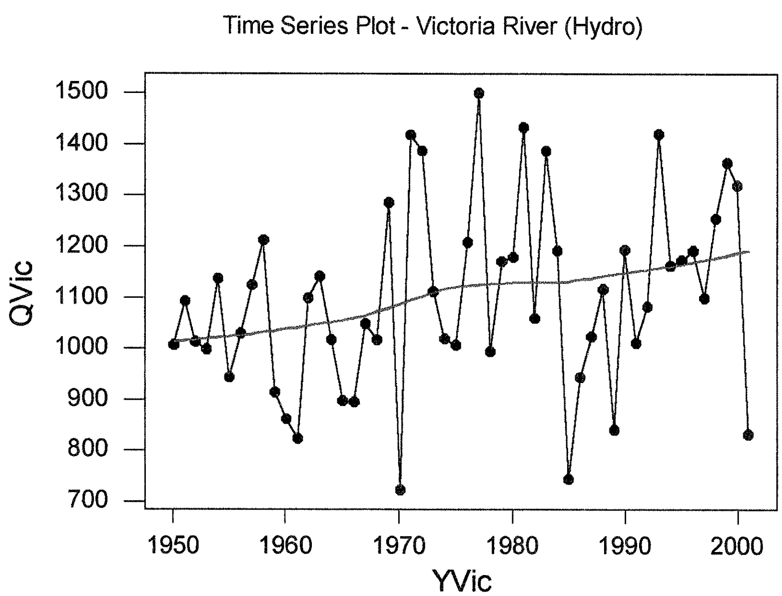


Time Series Plot - South West River (Natural)
QSW mm
1200
1100
1000
900
800
700
600
500
400
1970
1980
1990
2000
YSW

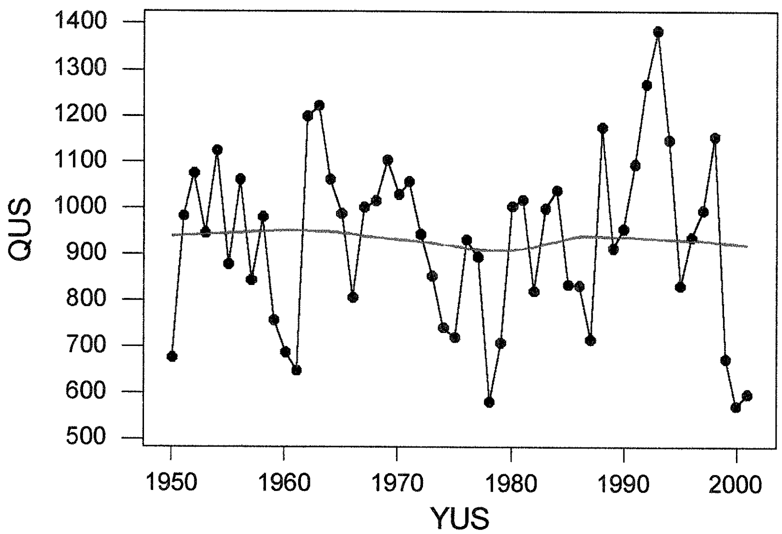

Time Series Plot - Isle Aux Morts River (Natural)
2900
2700
2500
2300
2100
1900
1700
1500
QI mm
1960
1970
1980
1990
2000
YI


Time Series Plot - Torrent River (Natural)
1800
1600
1400
1200
1000
QTor mm
1960
1970
1980
1990
2000
YTor

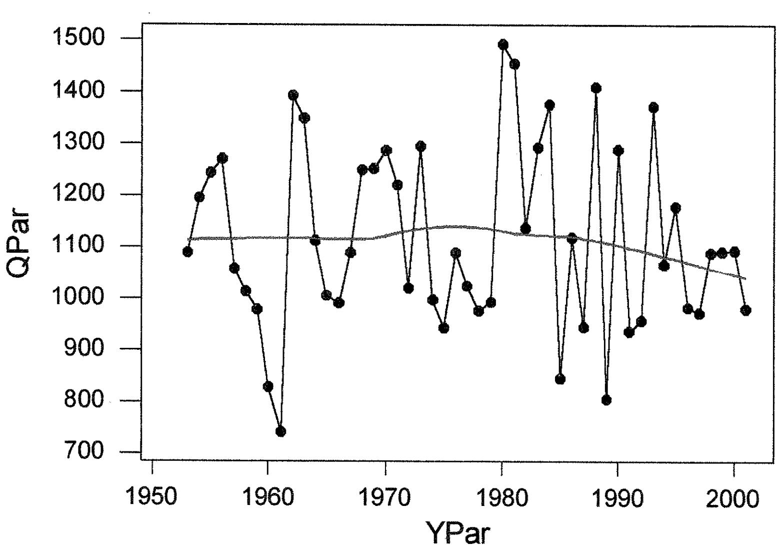

Time Series Plot - Lower Salmon River (Hydro)
1300
1200
1100
1000
900
800
700
600
QLS
1950
1960
1970
1980
1990
2000
YLS


Time Series Plot - Victoria River (Hydro)
1500
1400
1300
1200
1100
1000
900
800
700
QVic
1950
1960
1970
1980
1990
2000
YVic

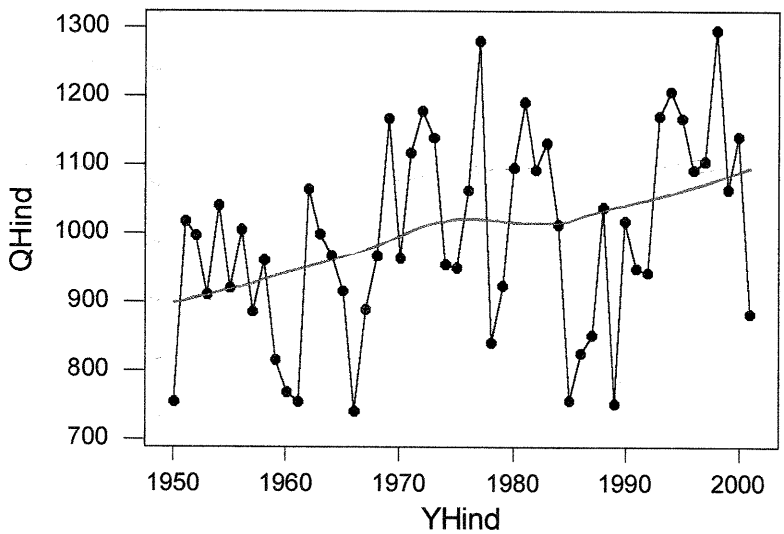
Time Series Plot - Upper Salmon River (Hydro)



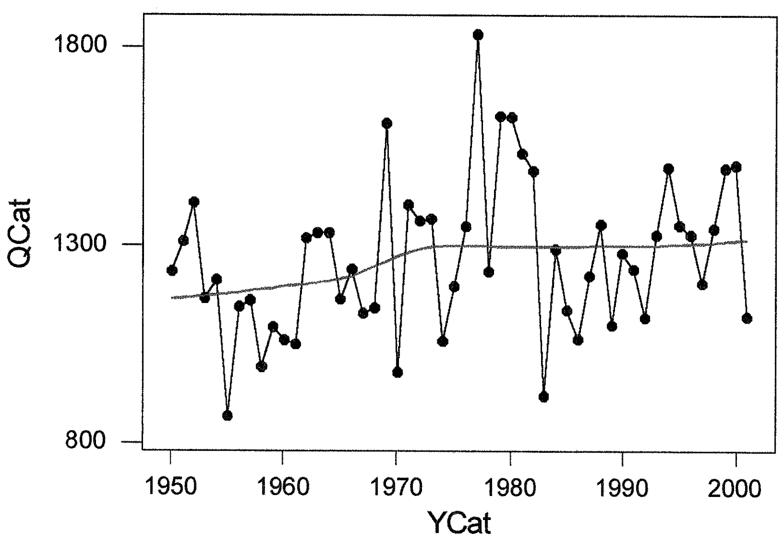
Time Series Plot - Paradise River (Hydro)



Time Series Plot - Hind's Lake (1950-2001)



Time Series Plot - Cat Arm River (1950-2001)

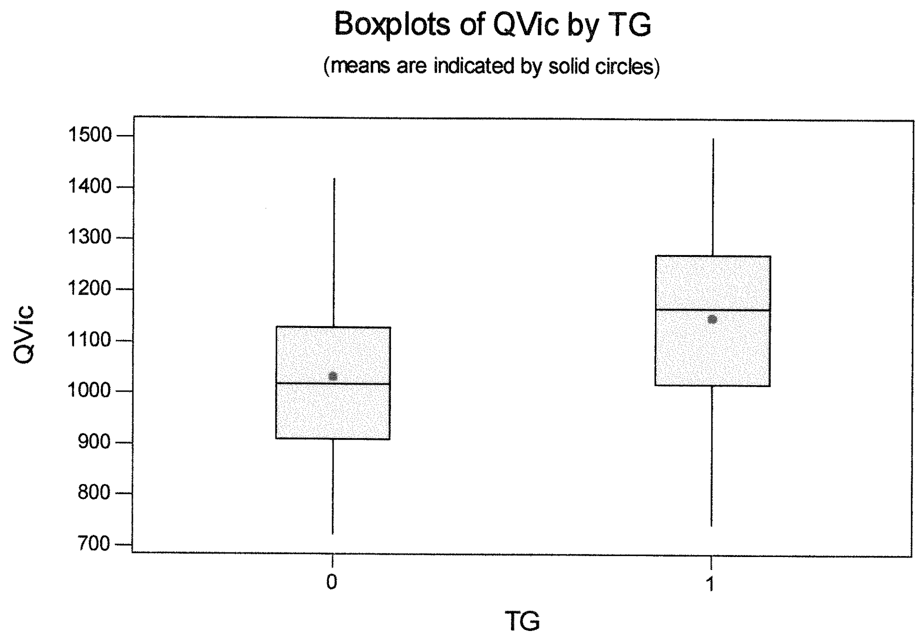


Appendix G

Box Plots and Probability Plots

Appendix G
Glossary of Abbreviations

Bay – Bay du Nord River
Cat – Cat Arm River
Gan – Gander River
Grey – Grey River
Hind – Hinds Lake
Lew – Leewaseechjeech River
LS – Lower Salmon River
Par – Paradise River
Pip – Pipers Hole River
UH – Upper Humber River
US – Upper Salmon River
Vic – Victoria River



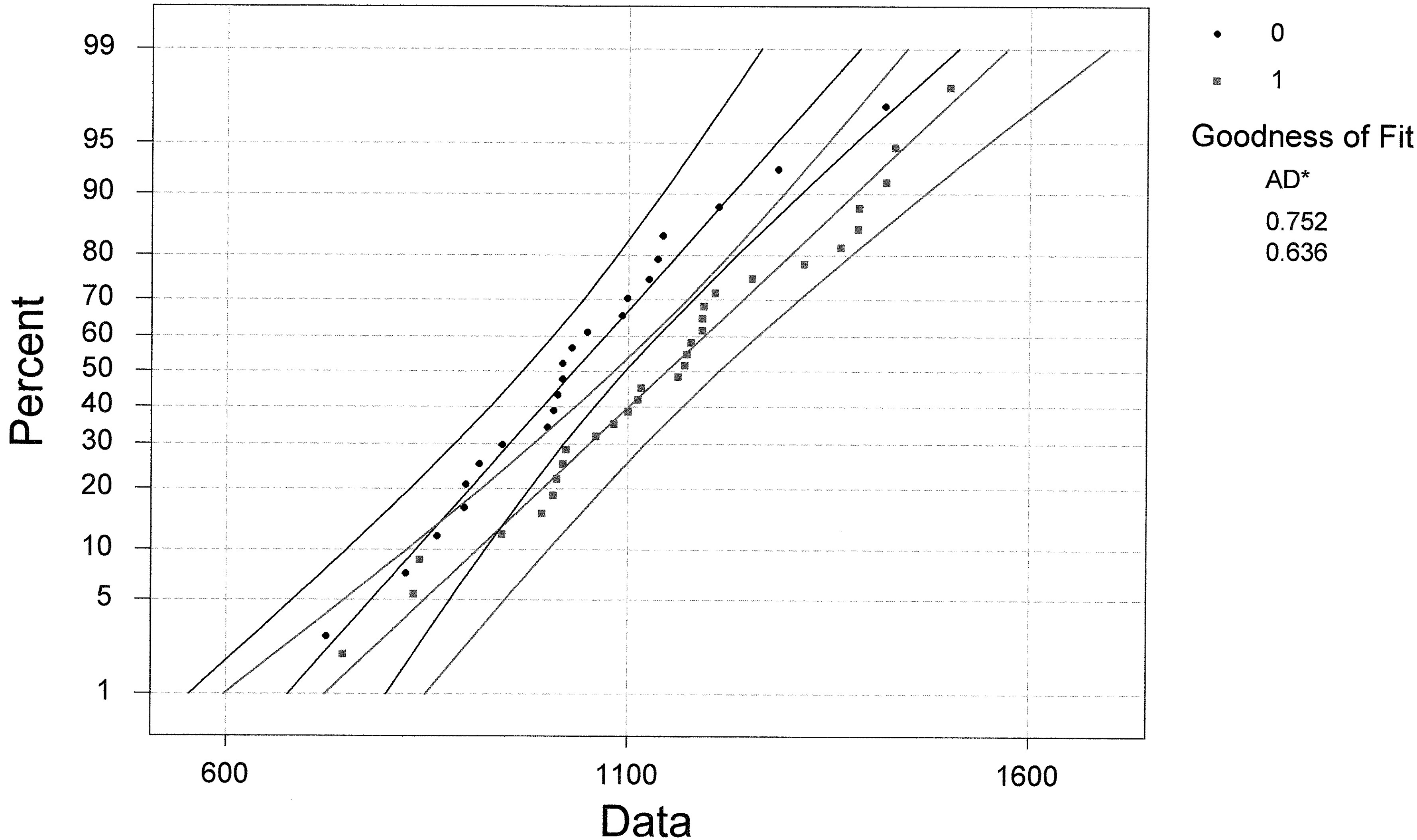
Two-Sample T-Test and CI: QVic, TG

```
Two-sample T for QVic

TG          N      Mean     StDev   SE Mean
0          22      1032       157        33
1          30      1147       186        34

Difference = mu (0) - mu (1)
Estimate for difference:  -115.4
95% CI for difference: (-211.1, -19.7)
T-Test of difference = 0 (vs not =): T-Value = -2.42  P-Value = 0.019  DF = 48
```

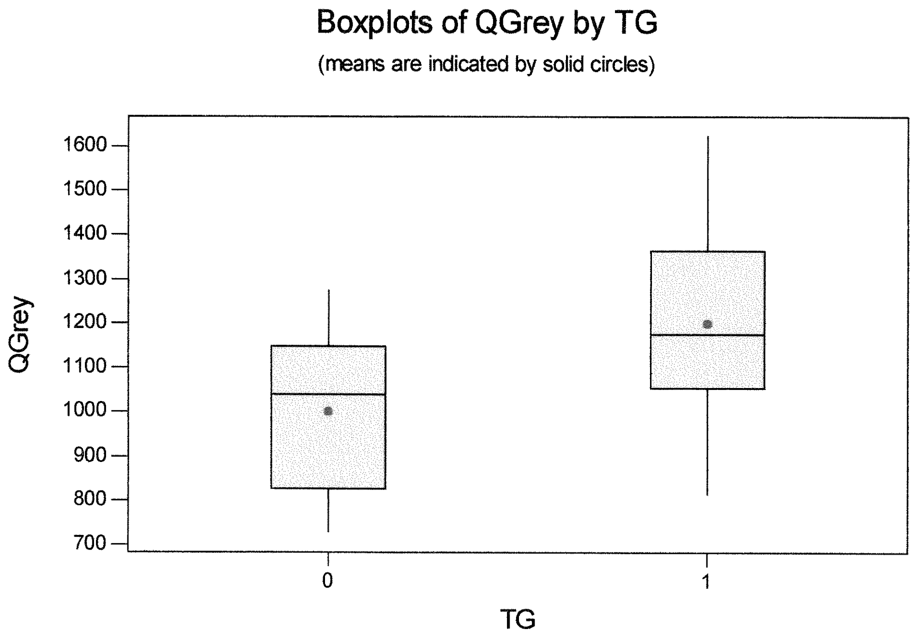
0 = Prior to 1971
1 = after 1971

Normal Probability Plot for QVic By TG

ML Estimates - 95% CI



G2



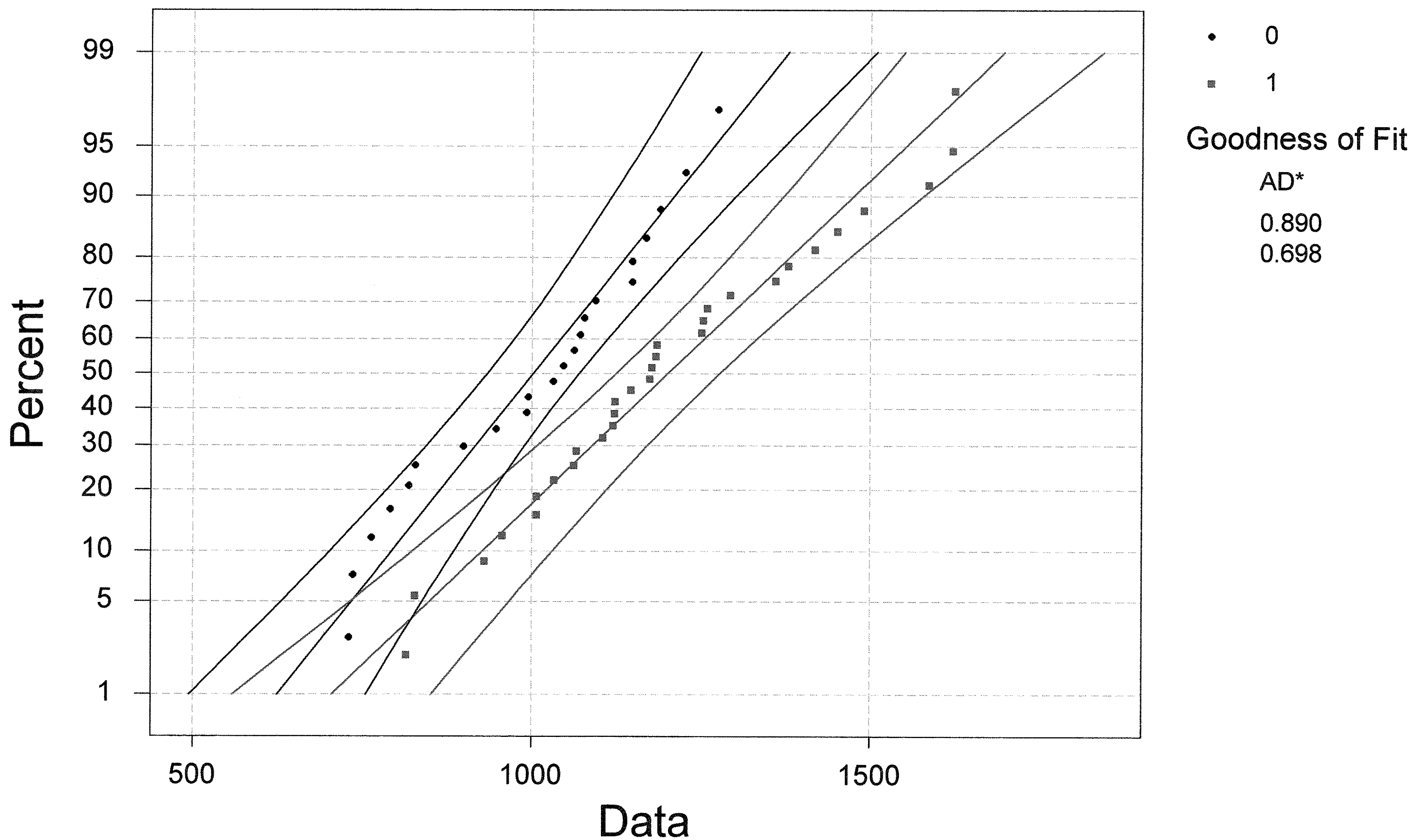
Two-Sample T-Test and CI: QGrey, TG

```
Two-sample T for QGrey

TG          N      Mean     StDev   SE Mean
0          22      1001       166        35
1          30      1201       217        40

Difference = mu (0) - mu (1)
Estimate for difference:  -199.4
95% CI for difference: (-306.1, -92.6)
T-Test of difference = 0 (vs not =): T-Value = -3.75  P-Value = 0.000  DF = 49
```

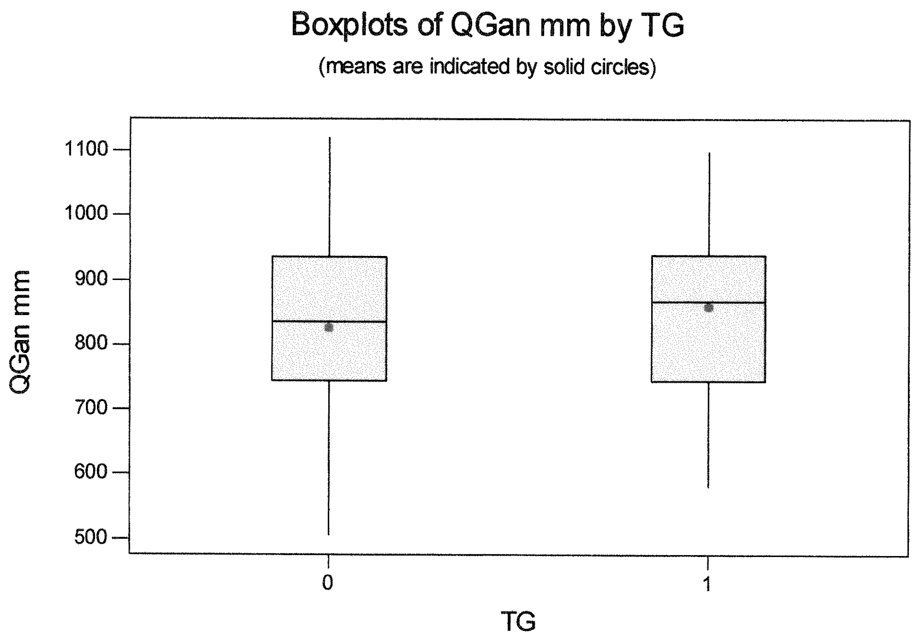
0 = prior to 1971
1 = after 1971

Normal Probability Plot for QGrey By TG

ML Estimates - 95% CI



G4



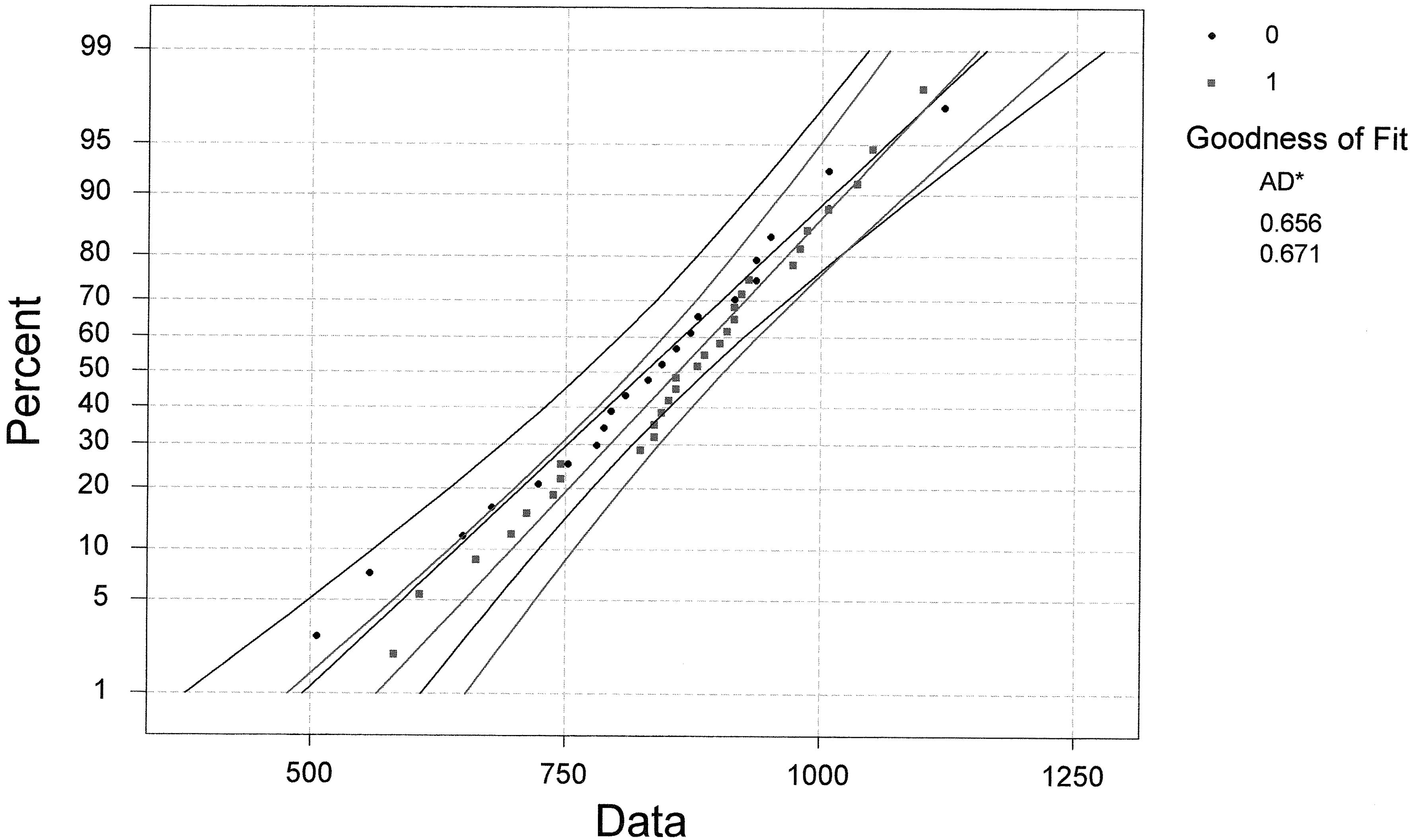
Two-Sample T-Test and CI: QGan mm, TG

```
Two-sample T for QGan mm

TG          N      Mean     StDev    SE Mean
0          22       827       147         31
1          30       859       129         24

Difference = mu (0) - mu (1)
Estimate for difference:  -32.6
95% CI for difference: (-111.7, 46.6)
T-Test of difference = 0 (vs not =): T-Value = -0.83  P-Value = 0.411  DF = 41
```

0 = prior to 1971
1 = after 1971

Normal Probability Plot for QGan mm By TG

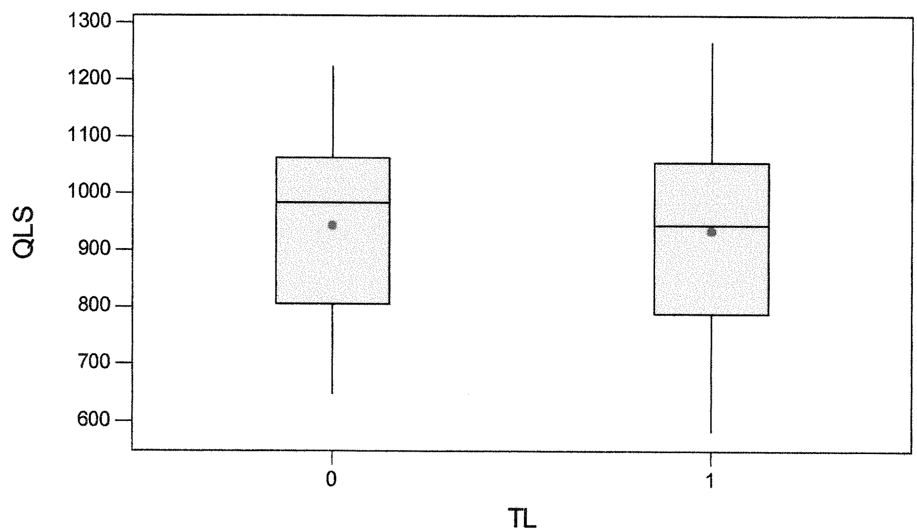
ML Estimates - 95% CI



G6

Boxplots of QLS by TL

(means are indicated by solid circles)



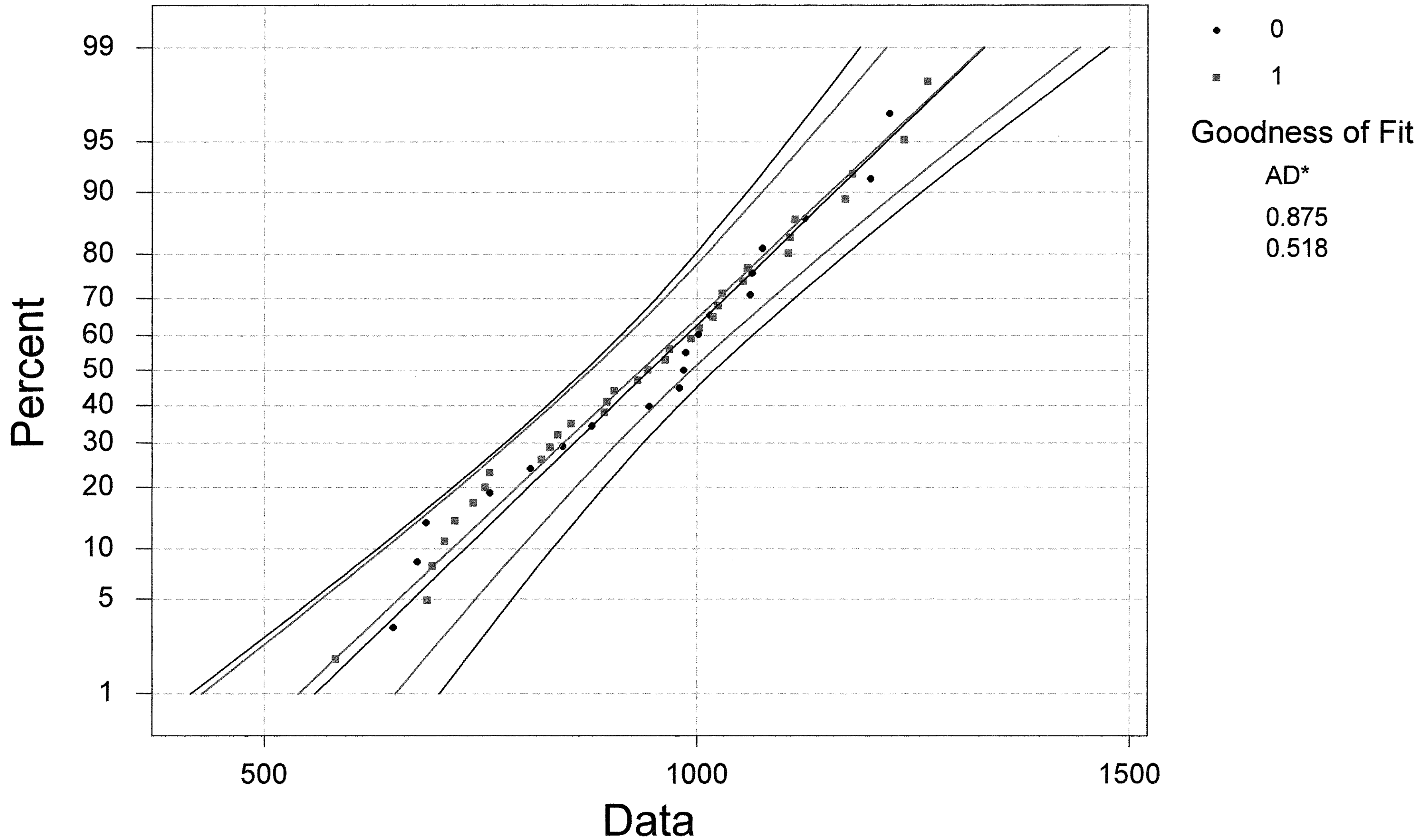
Two-Sample T-Test and CI: QLS, TL

```
Two-sample T for QLS

TL           N      Mean     StDev   SE Mean
0           19       945       171        39
1           33       935       173        30

Difference = mu (0) - mu (1)
Estimate for difference:  10.1
95% CI for difference: (-90.0, 110.2)
T-Test of difference = 0 (vs not =): T-Value = 0.20  P-Value = 0.839  DF = 38
```

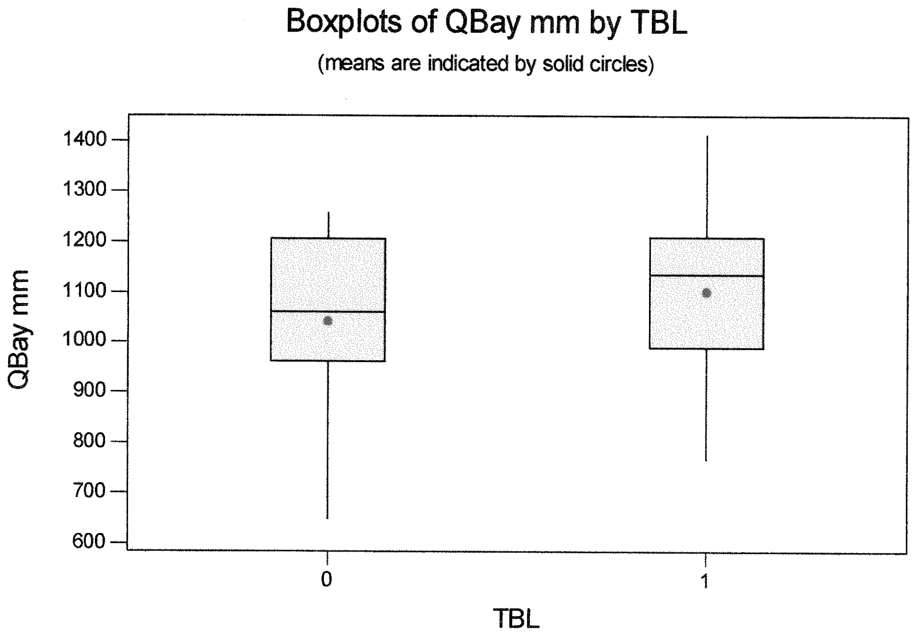
0 = before 1969
1 = after 1969

Normal Probability Plot for QLS By TL

ML Estimates - 95% CI



G8



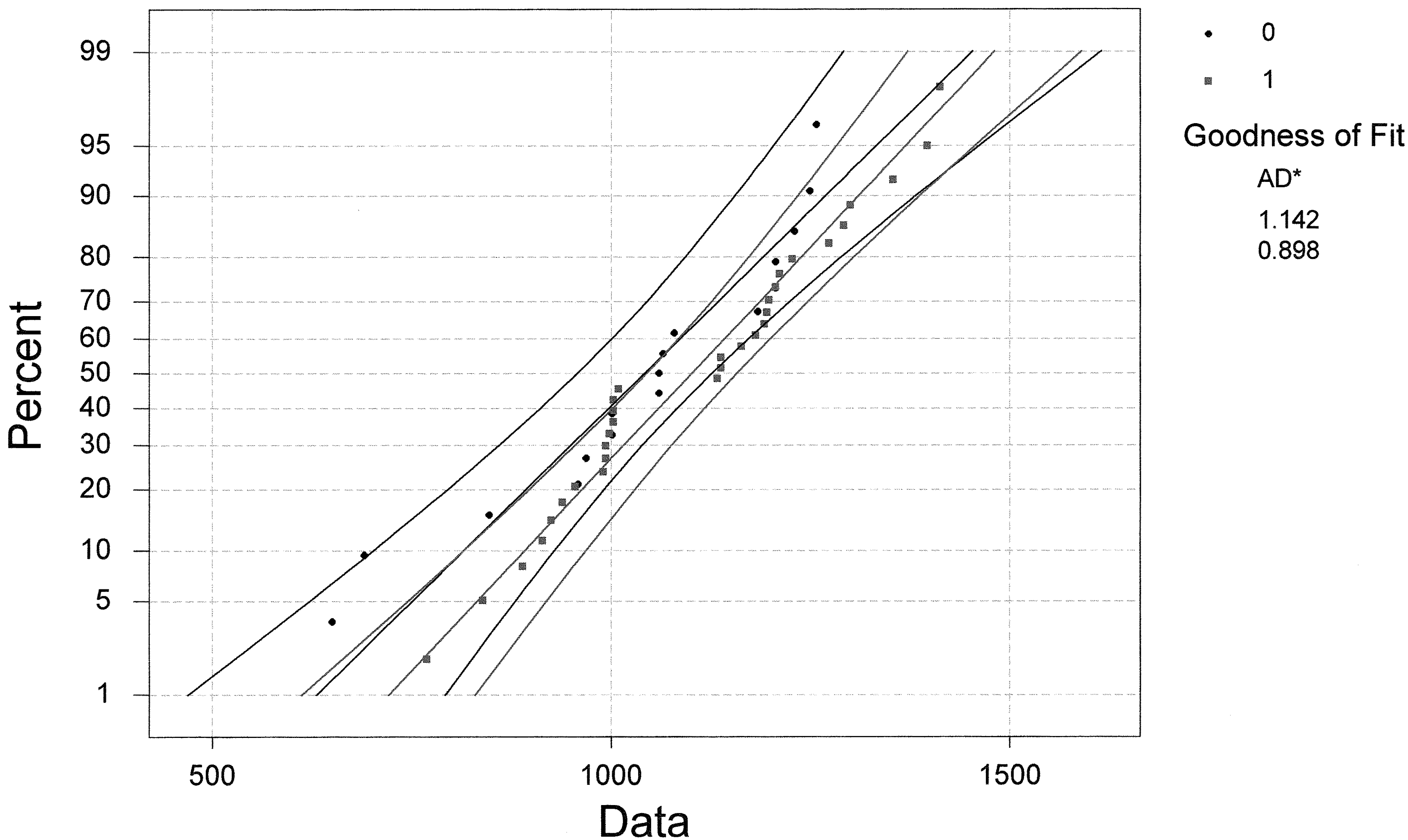
Two-Sample T-Test and CI: QBay mm, TBL

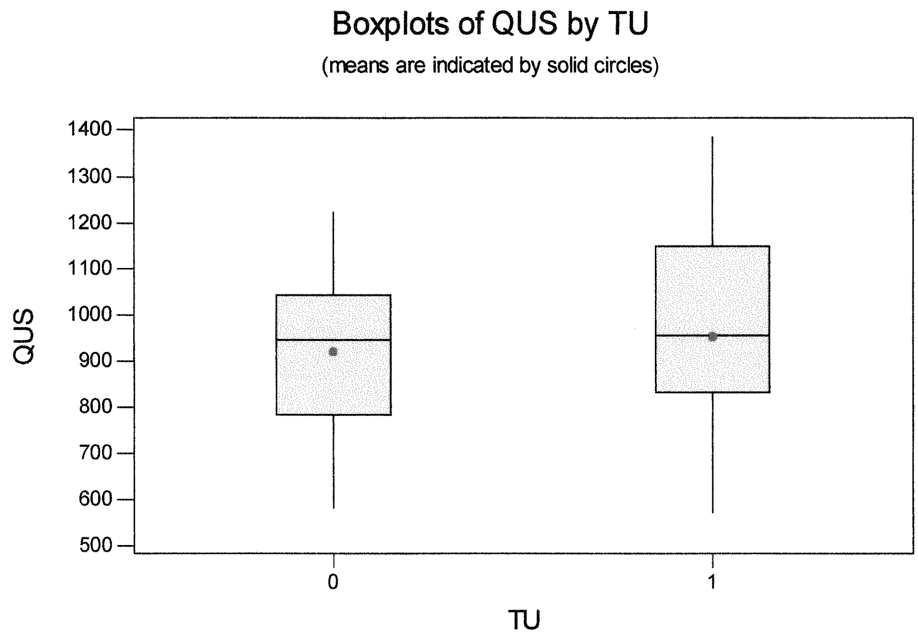
```
Two-sample T for QBay mm

TBL          N      Mean     StDev   SE Mean
0           17      1042       182        44
1           32      1101       166        29

Difference = mu (0) - mu (1)
Estimate for difference:  -59.2
95% CI for difference: (-167.6, 49.2)
T-Test of difference = 0 (vs not =): T-Value = -1.12  P-Value = 0.274  DF = 30
```

0 = before 1969
1 = after 1969

Normal Probability Plot for QBay mm By TBL

ML Estimates - 95% CI





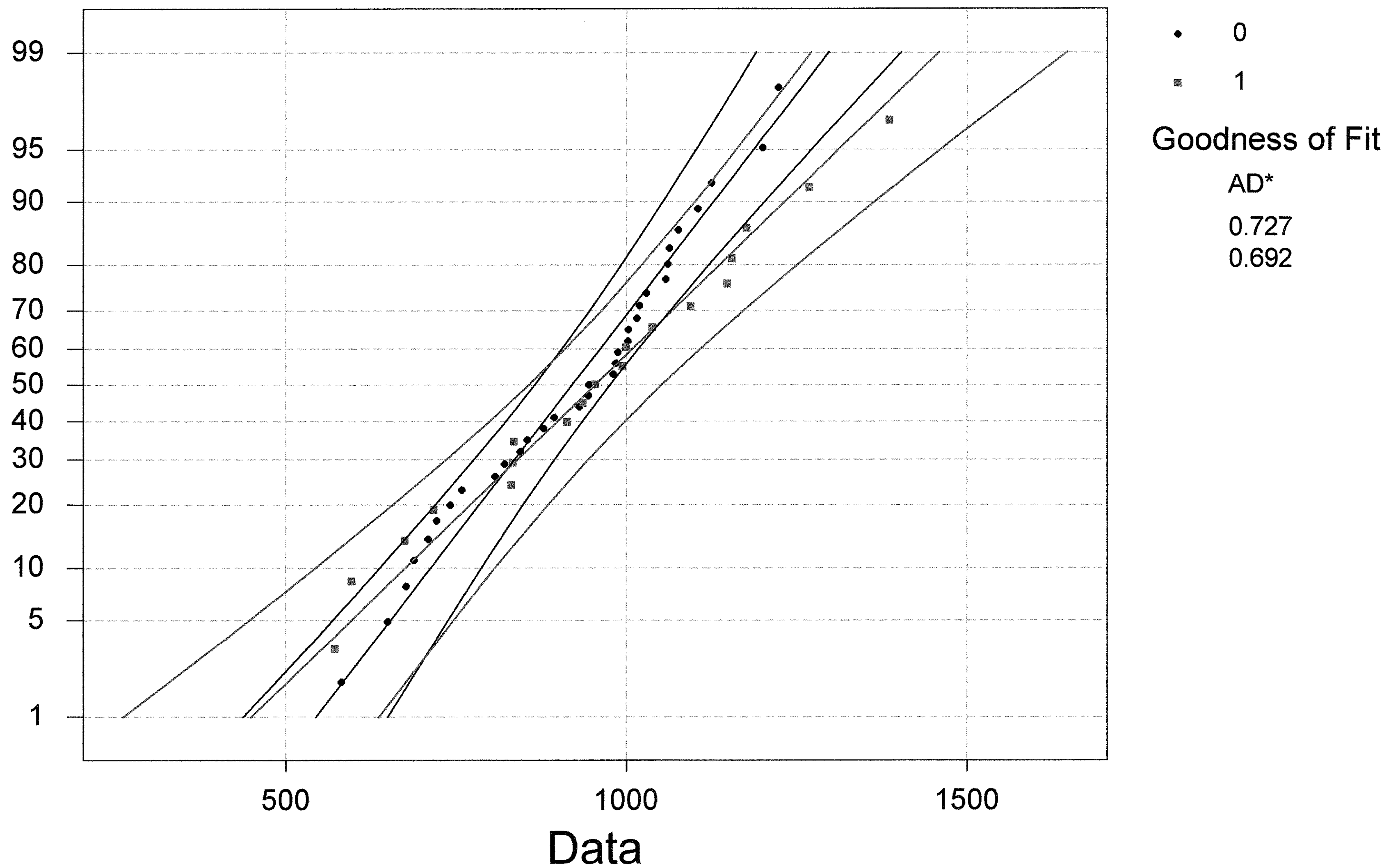
Two-Sample T-Test and CI: QUS, TU

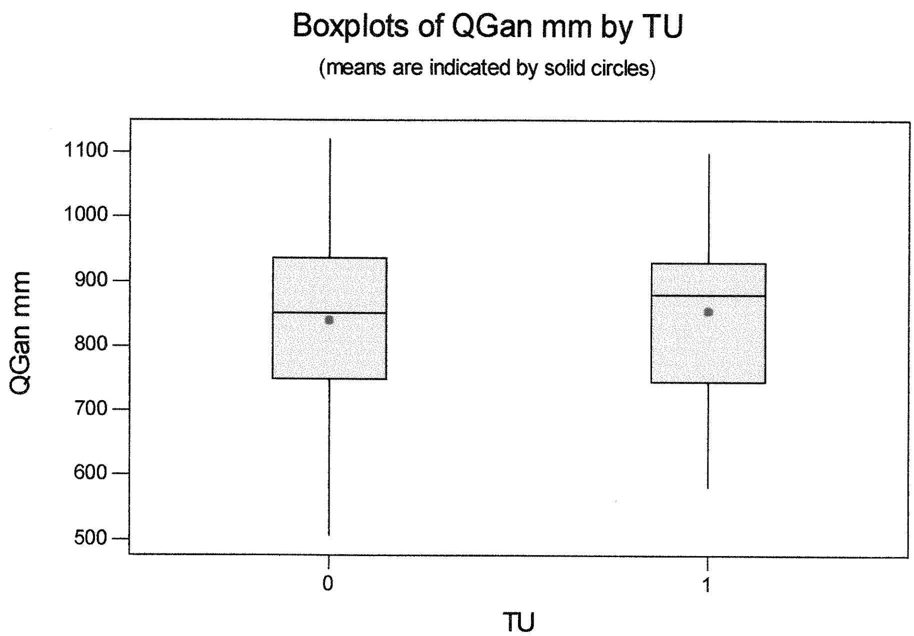
```
Two-sample T for QUS

TU           N      Mean     StDev   SE Mean
0           33       920       165        29
1           19       954       223        51

Difference = mu (0) - mu (1)
Estimate for difference:  -33.7
95% CI for difference: (-153.7, 86.4)
T-Test of difference = 0 (vs not =): T-Value = -0.57  P-Value = 0.571  DF = 29
```

0 = Before 1983
1 = After 1983

Normal Probability Plot for QUS By TU

ML Estimates - 95% CI

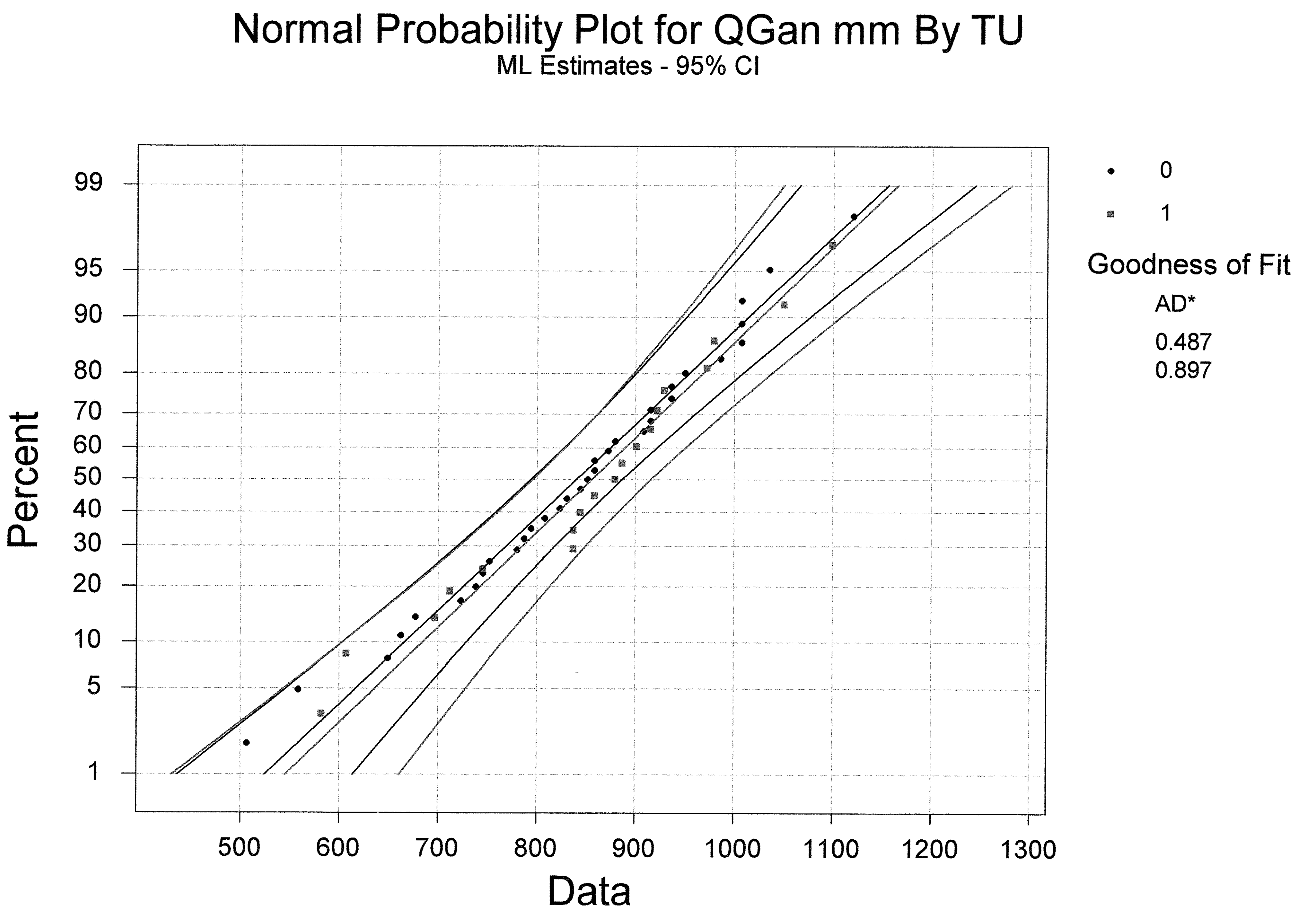




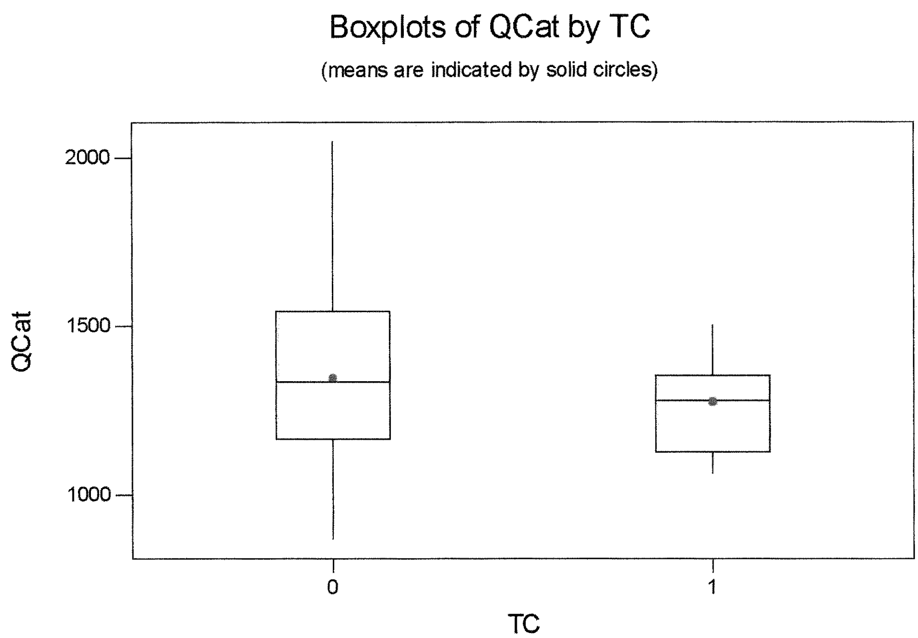
Two-Sample T-Test and CI: QGan mm, TU

```
Two-sample T for QGan mm

TU           N      Mean     StDev   SE Mean
0           33       840       138        24
1           19       855       137        31

Difference = mu (0) - mu (1)
Estimate for difference:  -15.4
95% CI for difference: (-95.6, 64.7)
T-Test of difference = 0 (vs not =): T-Value = -0.39  P-Value = 0.699  DF = 37
```

0 = Before 1983
1 = after 1983



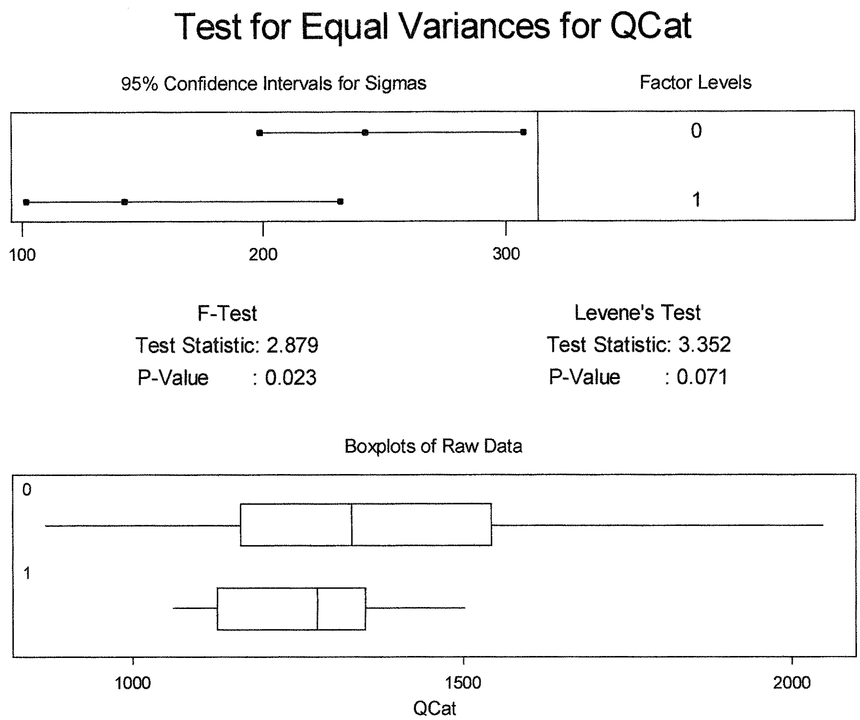
Normal Probability Plot for QGan mm By TU
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
500
600
700
800
900
1000
1100
1200
1300
Data
0
1
Goodness of Fit
AD*
0.487
0.897



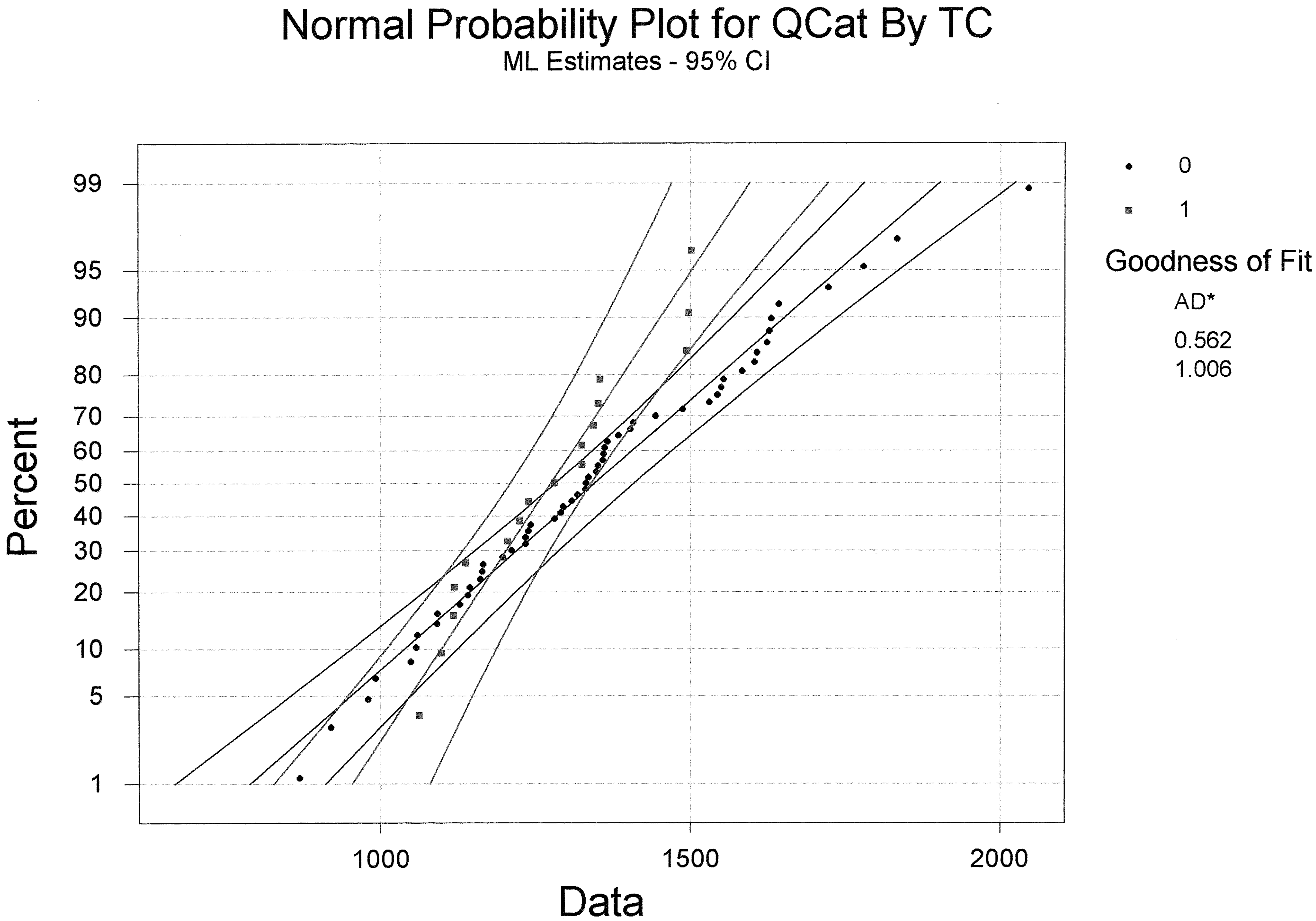
Two-Sample T-Test and CI: QCat, TC

```
Two-sample T for QCat

TC            N      Mean      StDev   SE Mean
0            55      1346        242        33
1            17      1275        142        35

Difference = mu (0) - mu (1)
Estimate for difference:  71.0
95% CI for difference: (-24.6, 166.6)
T-Test of difference = 0 (vs not =): T-Value = 1.49  P-Value = 0.142  DF = 46
```

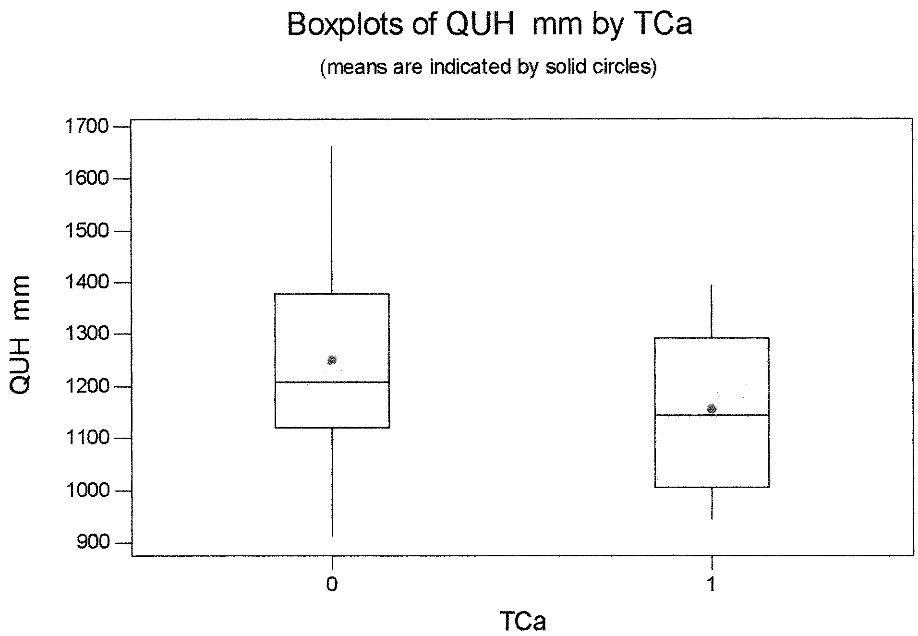
0 = Before 1985
1 = After 1985



Test for Equal Variances for QCat
95% Confidence Intervals for Sigmas
Factor Levels
0
1
100
200
300
F-Test
Test Statistic: 2.879
P-Value : 0.023
Levene's Test
Test Statistic: 3.352
P-Value : 0.071
Boxplots of Raw Data
0
1
1000
1500
2000
QCat



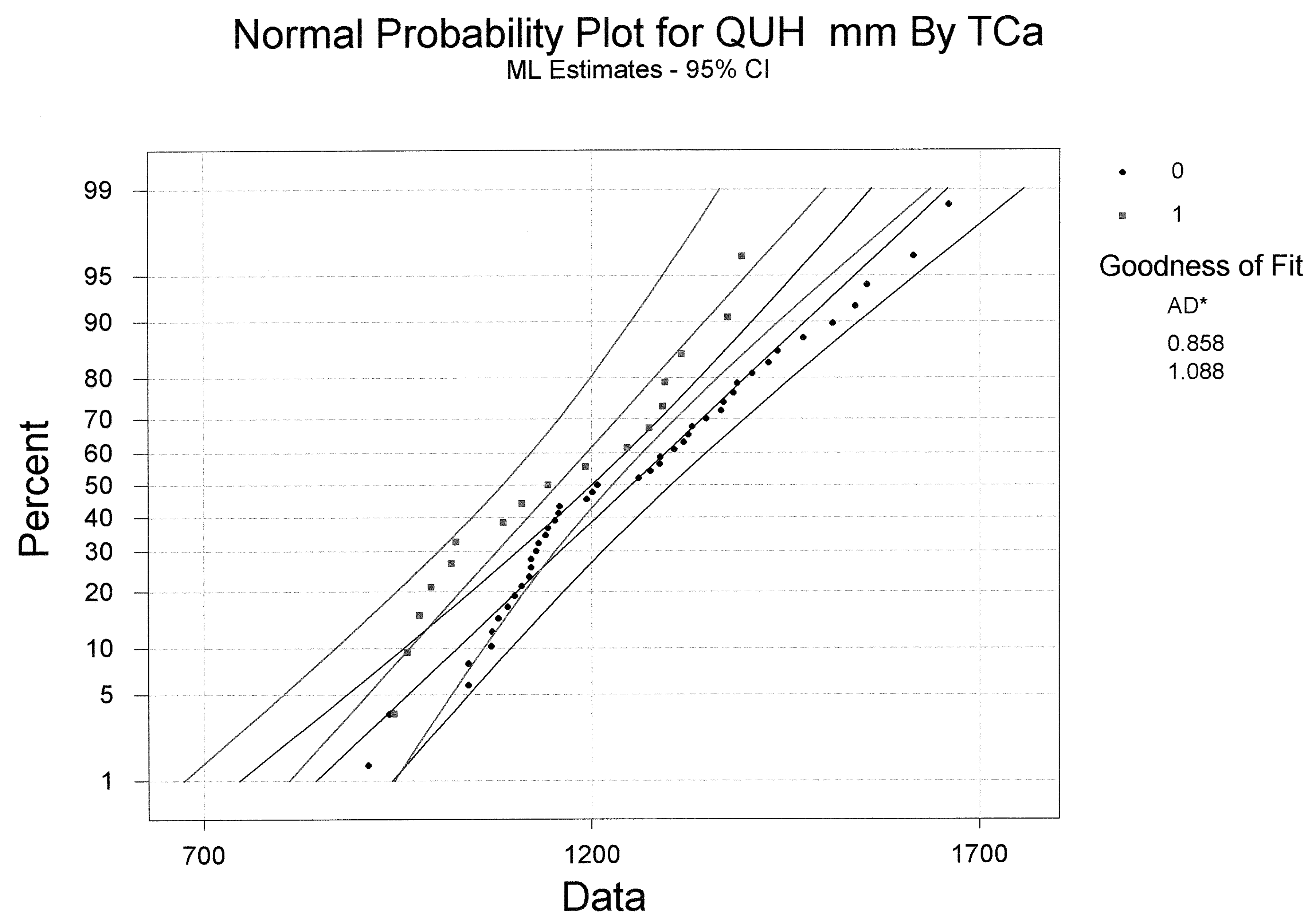
Normal Probability Plot for QCat By TC
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
1000
1500
2000
Data
0
1
Goodness of Fit
AD*
0.562
1.006

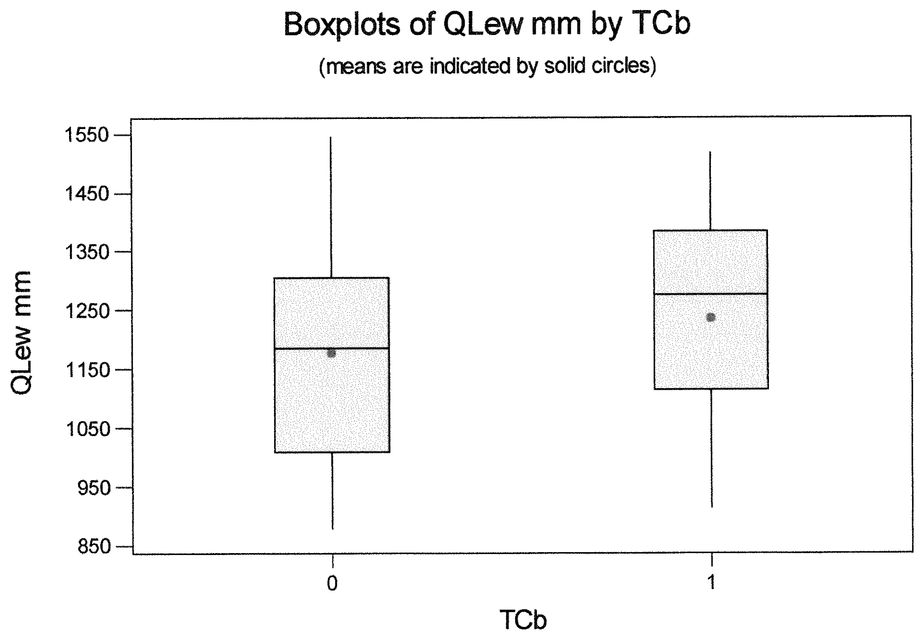


Two-Sample T-Test and CI: QUH mm, TCa

```
Two-sample T for QUH  mm

TCa           N     Mean    StDev  SE Mean
0            45     1252      177       26
1            17     1156      153       37

Difference = mu (0) - mu (1)
Estimate for difference:  95.9
95% CI for difference: (3.2, 188.6)
T-Test of difference = 0 (vs not =): T-Value = 2.10  P-Value = 0.043  DF = 33
```

0 = Before 1985
1 = After 1985


Normal Probability Plot for QUH mm By TCa
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
700
1200
1700
Data
0
1
Goodness of Fit
AD*
0.858
1.088



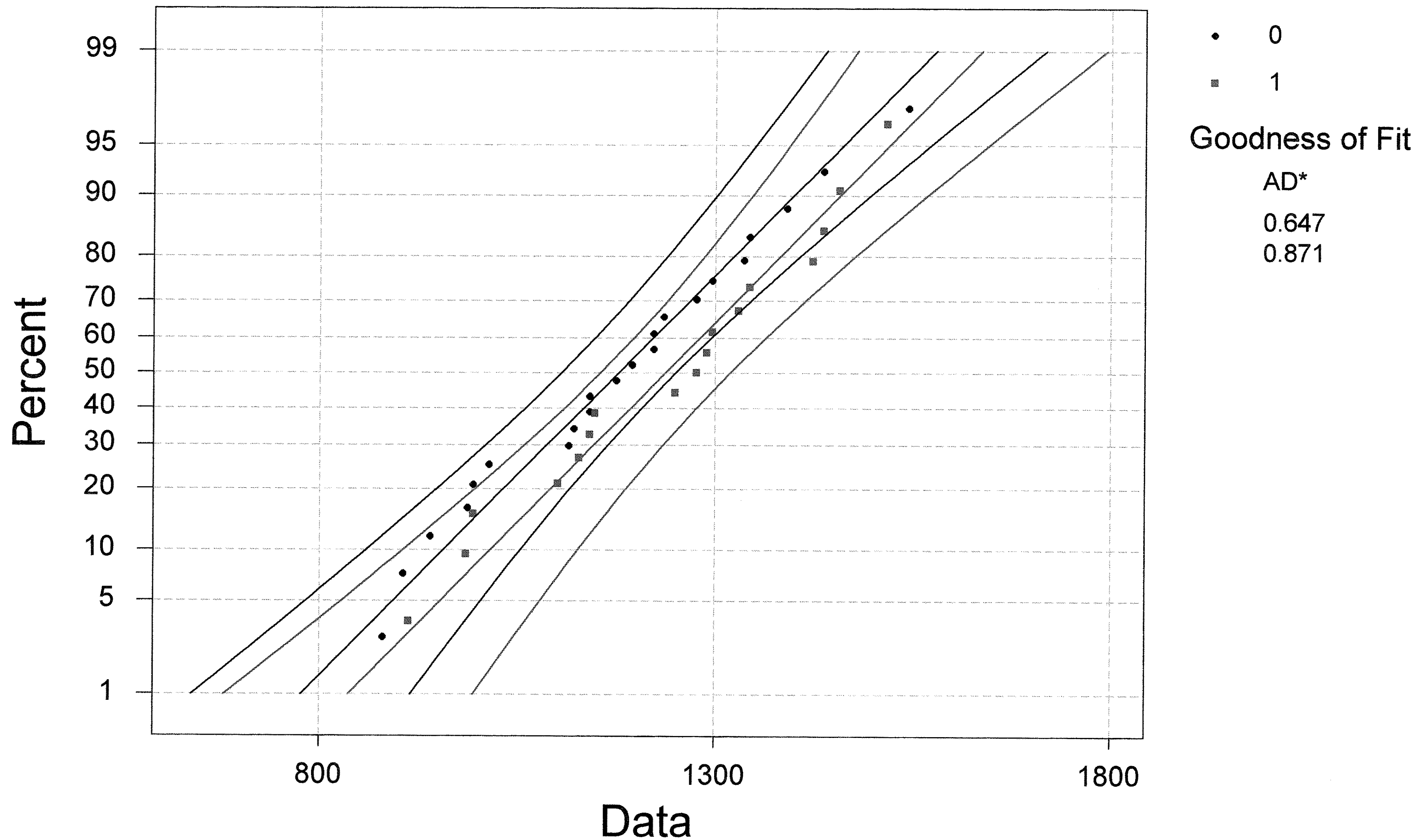
Two-Sample T-Test and CI: QLew mm, TCb

```
Two-sample T for QLew mm

TCb          N      Mean     StDev   SE Mean
0           22      1178       177        38
1           17      1237       177        43

Difference = mu (0) - mu (1)
Estimate for difference:  -59.1
95% CI for difference: (-175.3, 57.2)
T-Test of difference = 0 (vs not =): T-Value = -1.03  P-Value = 0.309  DF = 34
```

0 = Before 1985
1 = after 1985

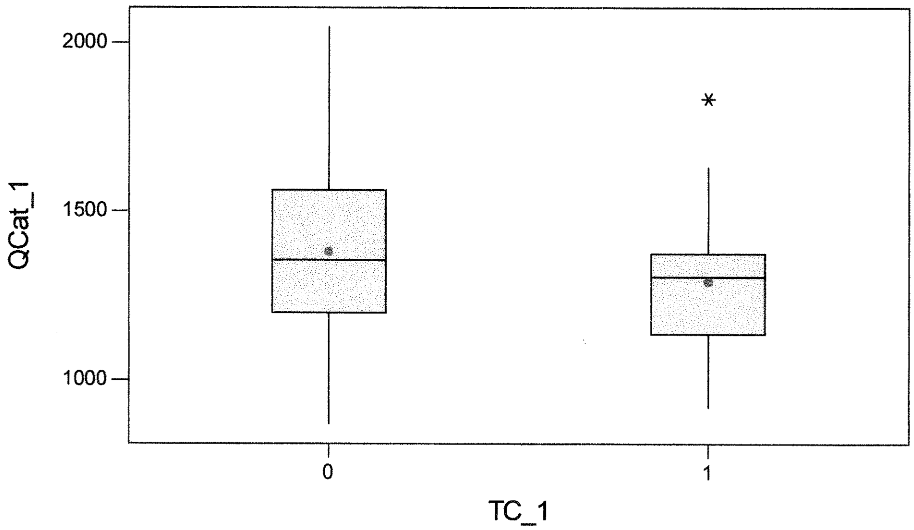
Normal Probability Plot for QLew mm By TCb

ML Estimates - 95% CI



Boxplots of QCat_1 by TC_1

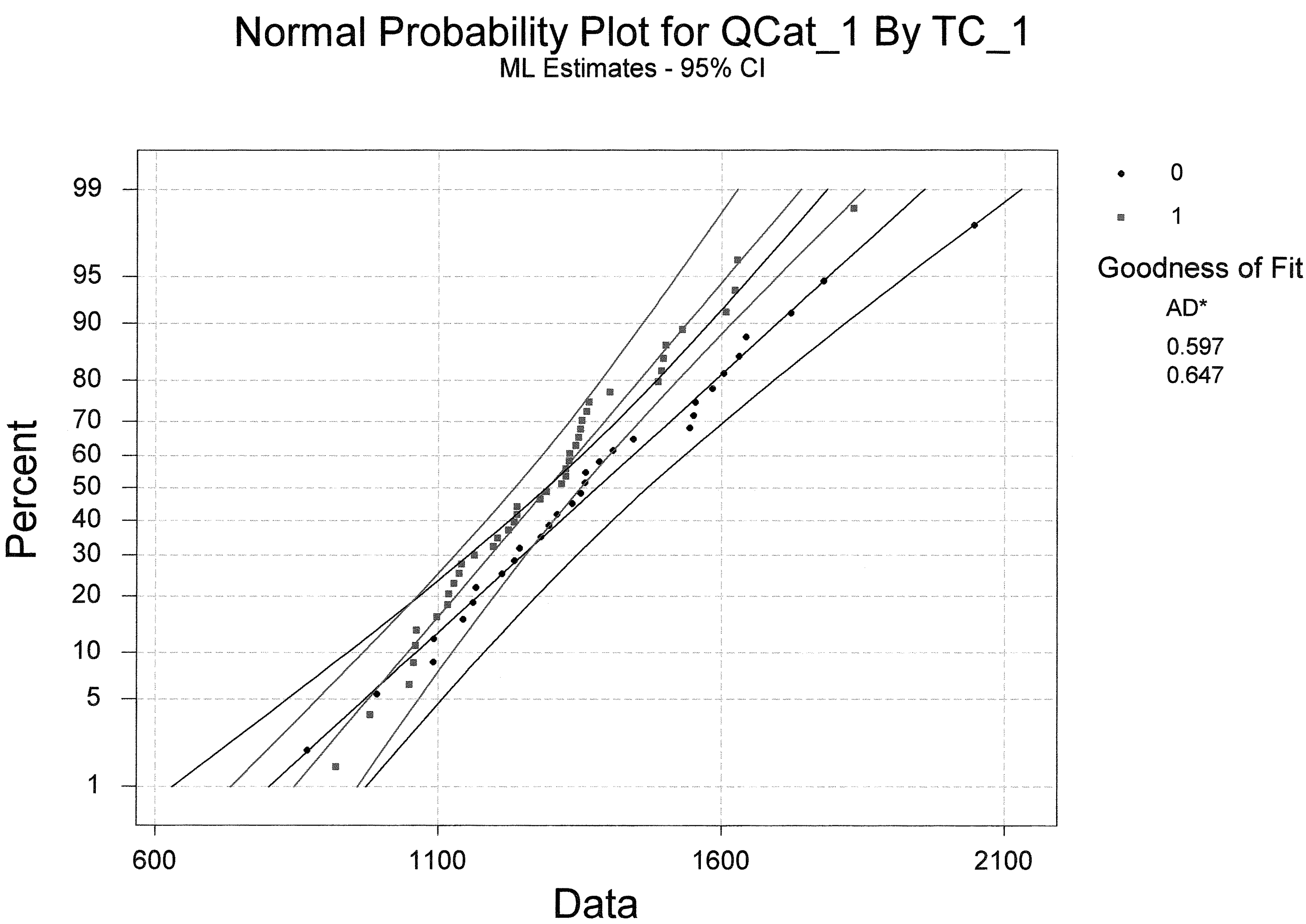
(means are indicated by solid circles)



Two-Sample T-Test and CI: QCat_1, TC_1

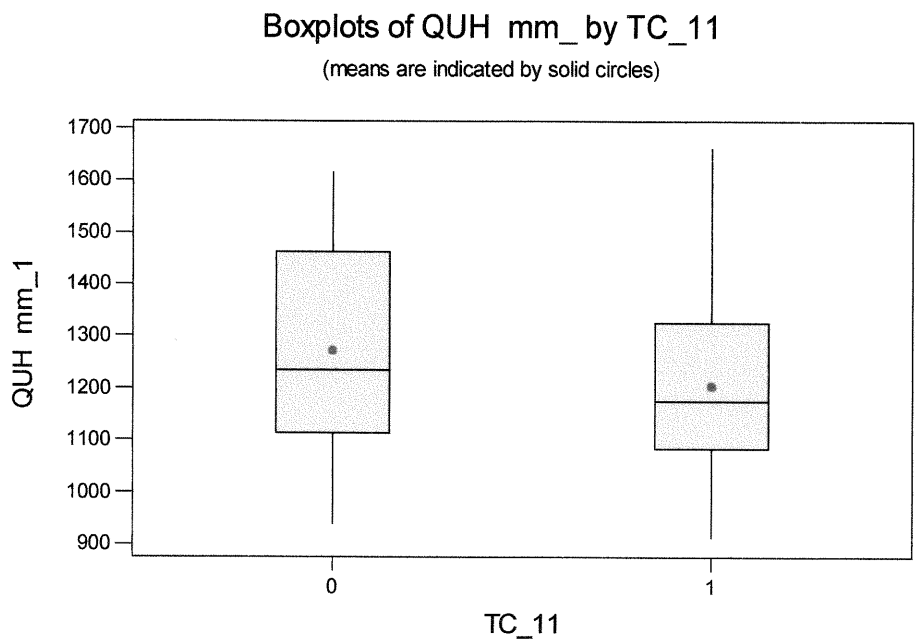
```
Two-sample T for QCat_1

TC_1         N      Mean     StDev   SE Mean
0           30      1380       253        46
1           42      1293       195        30

Difference = mu (0) - mu (1)
Estimate for difference:  86.7
95% CI for difference: (-24.0, 197.3)
T-Test of difference = 0 (vs not =): T-Value = 1.57  P-Value = 0.122  DF = 52
```

0 = Before 1959
1 = After 1959



Normal Probability Plot for QCat_1 By TC_1
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
600
1100
1600
2100
Data
0
1
Goodness of Fit
AD*
0.597
0.647

G23



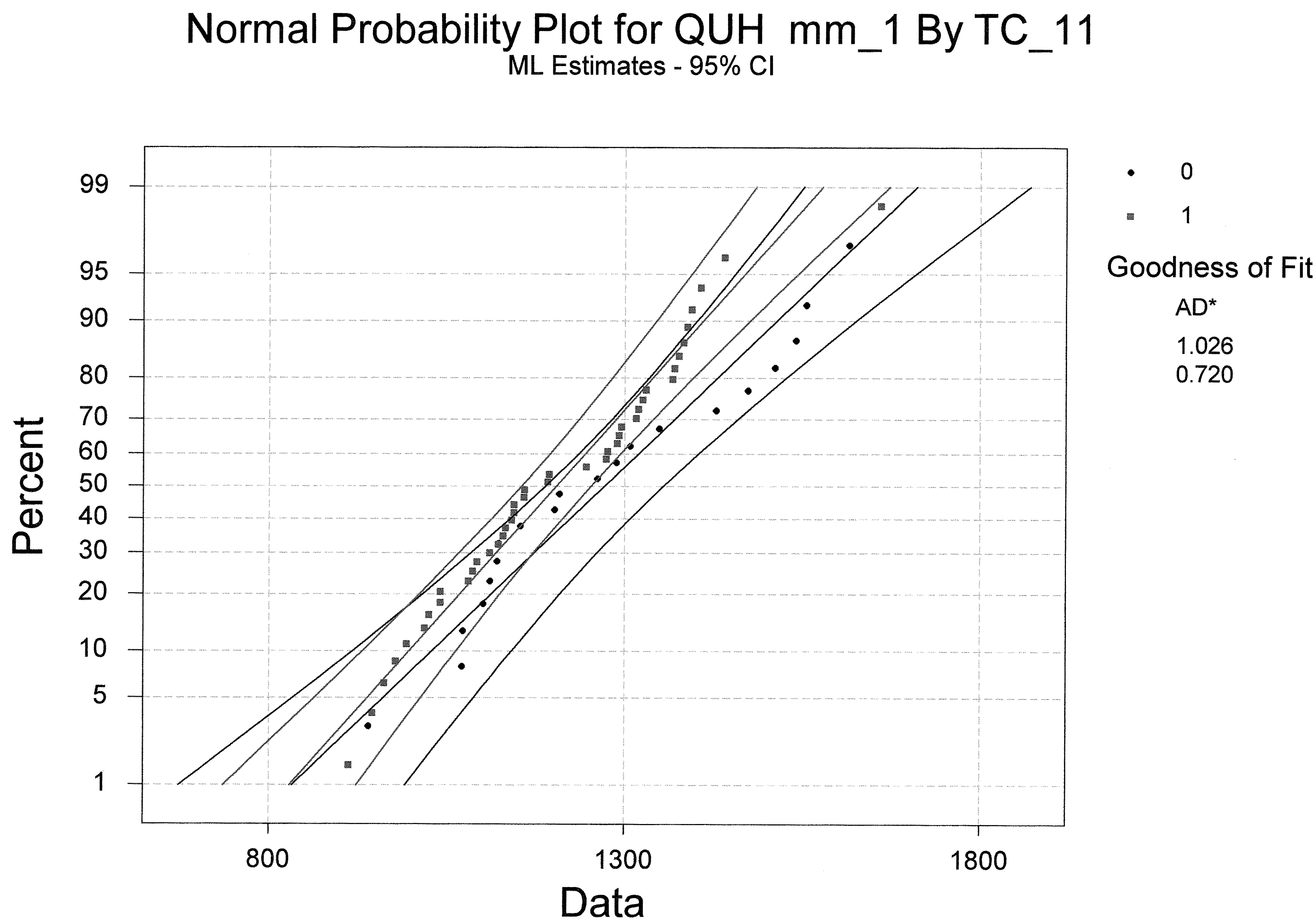
Two-Sample T-Test and CI: QUH mm_1, TC_11

Two-sample T for QUH mm_1

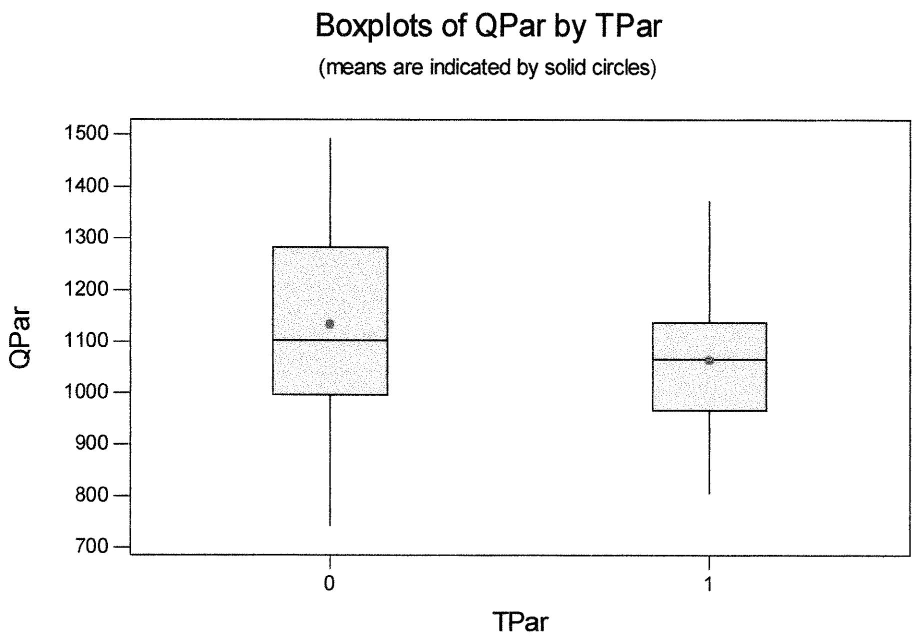
TC_11	N	Mean	StDev	SE Mean
0	20	1271	194	43
1	42	1203	163	25

Difference = mu (0) - mu (1)
Estimate for difference: 67.7
95% CI for difference: (-34.5, 169.8)
T-Test of difference = 0 (vs not =): T-Value = 1.35 P-Value = 0.187 DF = 32

0 = Before 1959
1 = After 1959


Normal Probability Plot for QUH mm_1 By TC_11
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
800
1300
1800
Data
0
1
Goodness of Fit
AD*
1.026
0.720

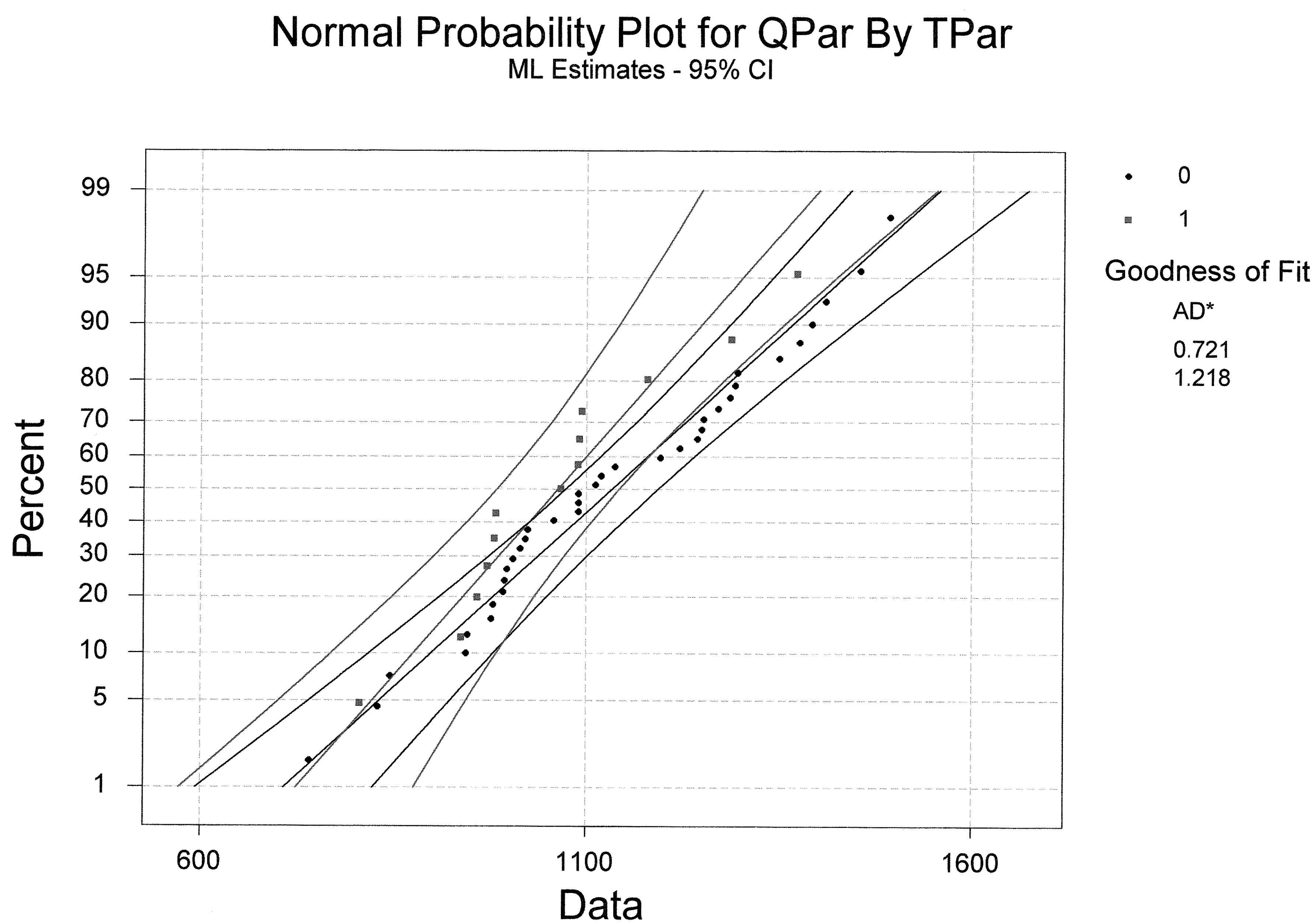
G25

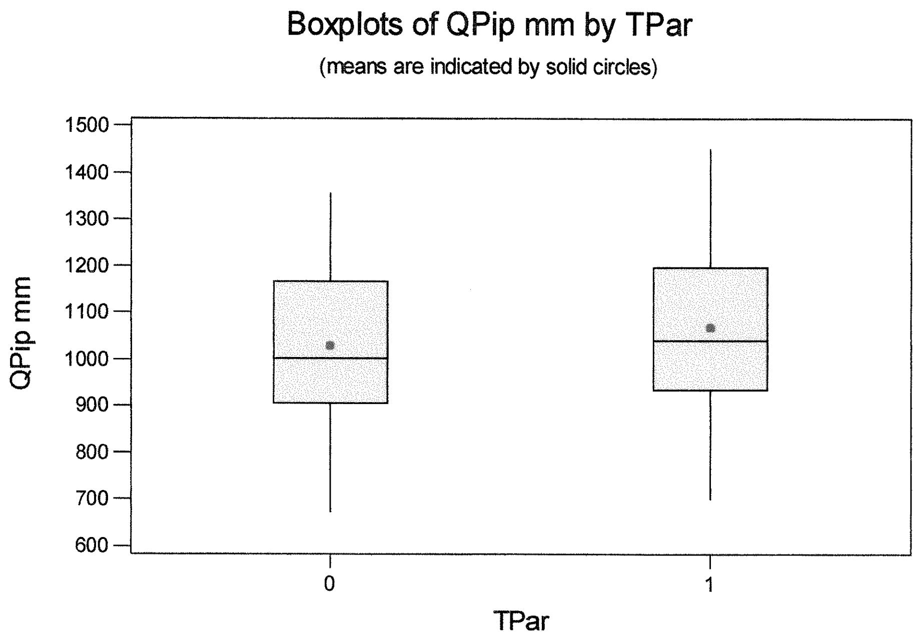


Two-Sample T-Test and CI: QPar, TPar

```
Two-sample T for QPar

TPar          N       Mean      StDev   SE Mean
0            36       1133        185        31
1            13       1063        152        42

Difference = mu (0) - mu (1)
Estimate for difference:  69.9
95% CI for difference: (-37.6, 177.4)
T-Test of difference = 0 (vs not =): T-Value = 1.34  P-Value = 0.192  DF = 25
```

0 = Before 1989
1 = After 1989

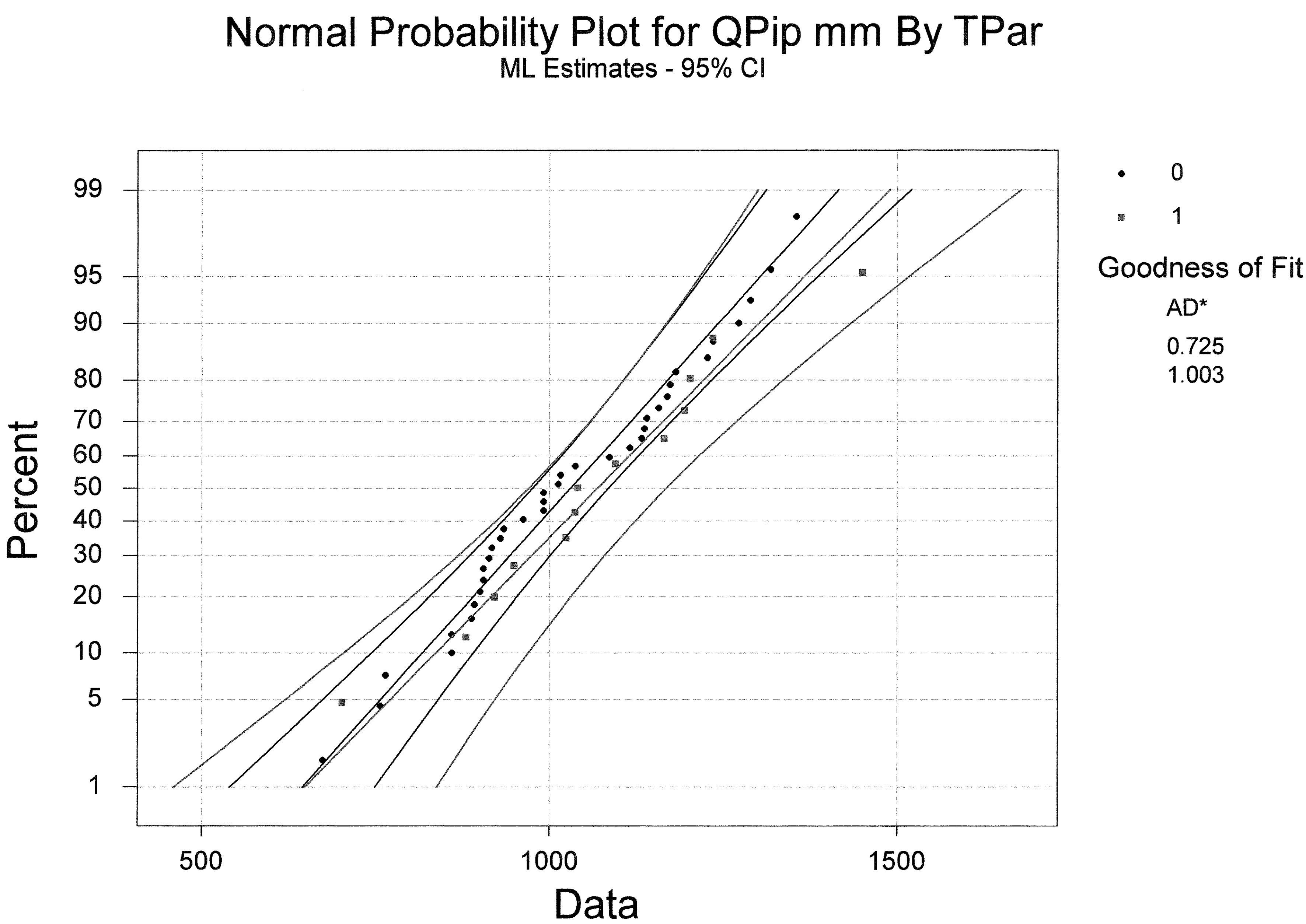

Normal Probability Plot for QPar By TPar
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
600
1100
1600
Data
0
1
Goodness of Fit
AD*
0.721
1.218



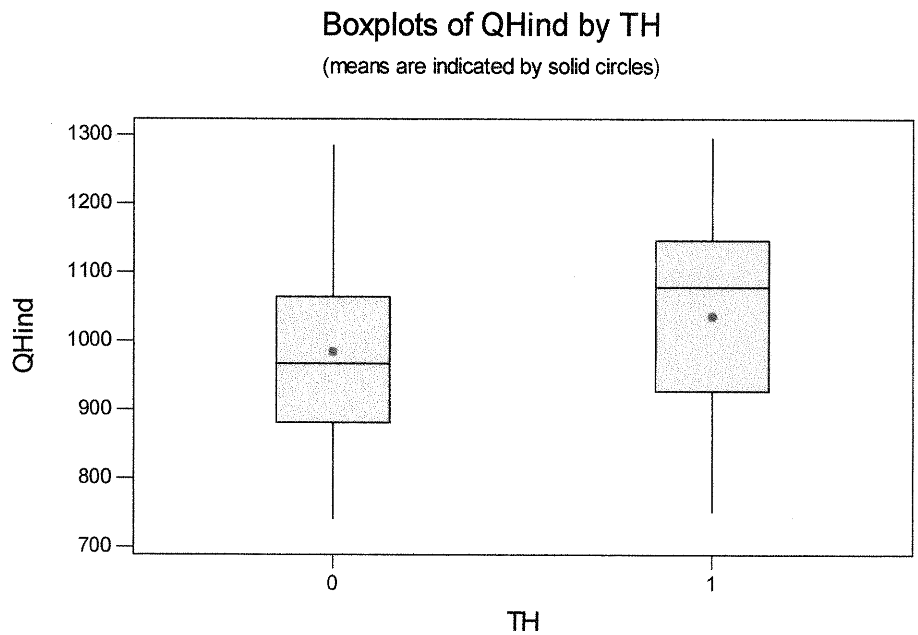
Two-Sample T-Test and CI: QPip mm, TPar

```
Two-sample T for QPip mm

TPar        N     Mean    StDev   SE Mean
0          36     1030      168        28
1          13     1069      189        52

Difference = mu (0) - mu (1)
Estimate for difference:  -38.9
95% CI for difference: (-163.1, 85.3)
T-Test of difference = 0 (vs not =): T-Value = -0.66  P-Value = 0.520  DF = 19
```

0 = Before 1989
1 = after 1989


Normal Probability Plot for QPip mm By TPar
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
500
1000
1500
Data
0
1
Goodness of Fit
AD*
0.725
1.003

G29



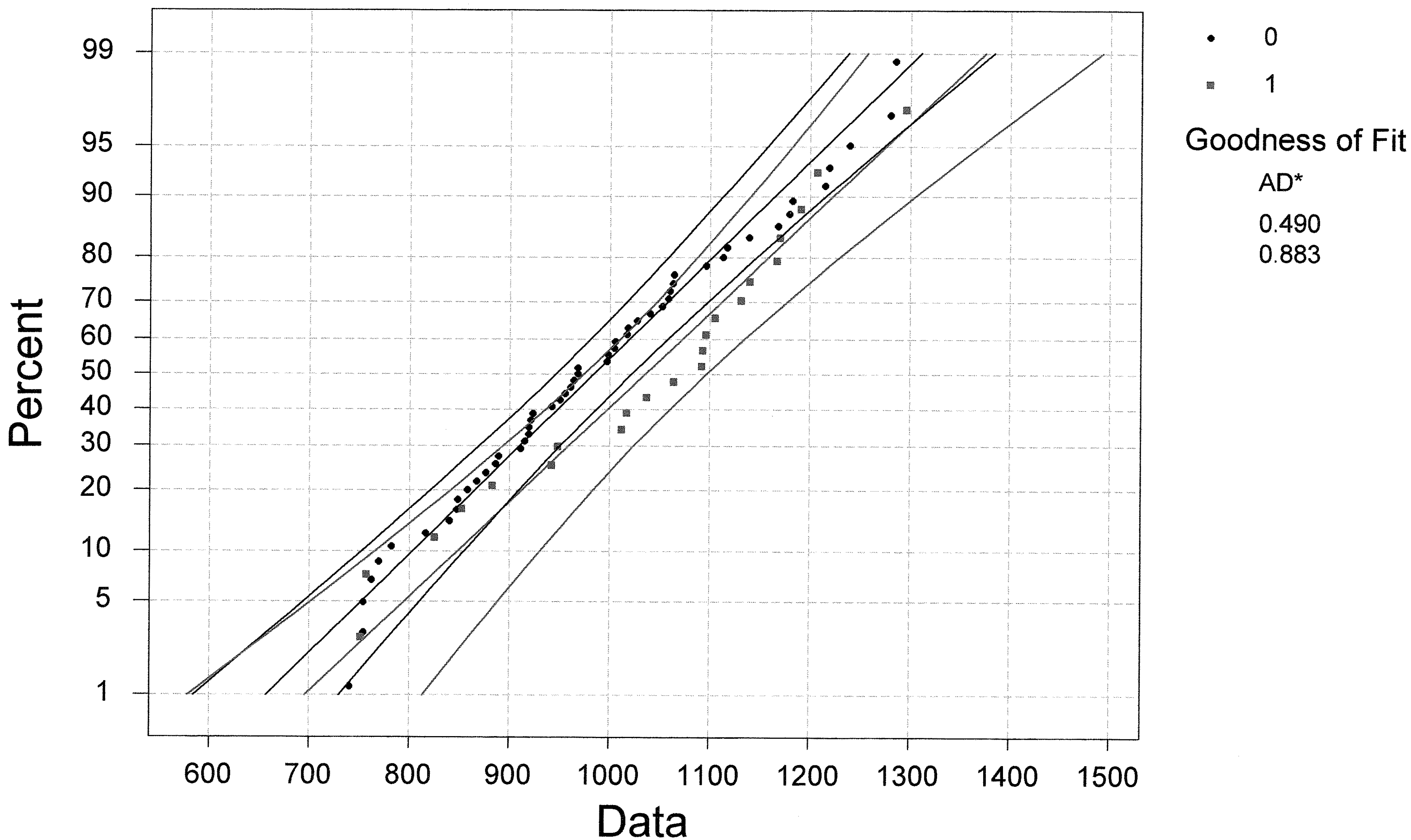
Two-Sample T-Test and CI: QHind, TH

```
Two-sample T for QHind

TH          N      Mean     StDev   SE Mean
0          53       984       142        20
1          22      1035       150        32

Difference = mu (0) - mu (1)
Estimate for difference:  -51.5
95% CI for difference: (-127.3, 24.2)
T-Test of difference = 0 (vs not =): T-Value = -1.38  P-Value = 0.176  DF = 37
```

0 = Before 1980
1 = After 1980

Normal Probability Plot for QHind By TH

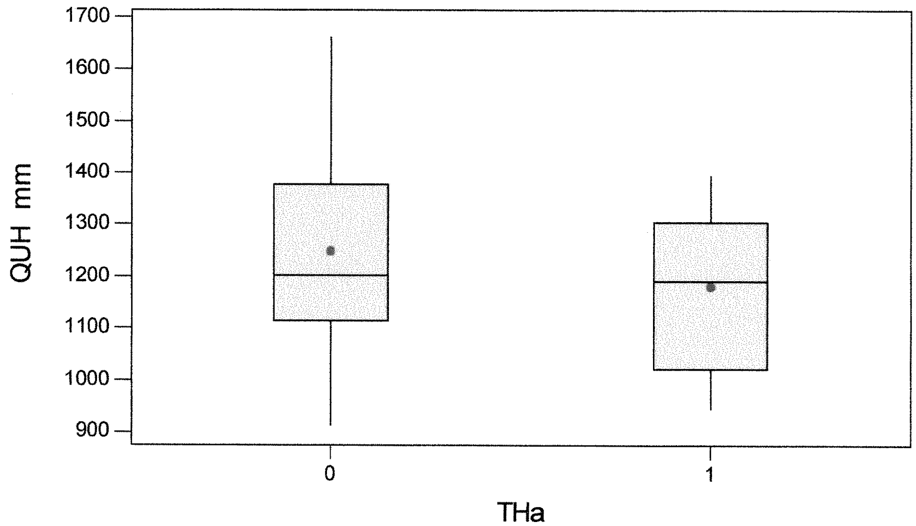
ML Estimates - 95% CI



G31

Boxplots of QUH mm by THa

(means are indicated by solid circles)



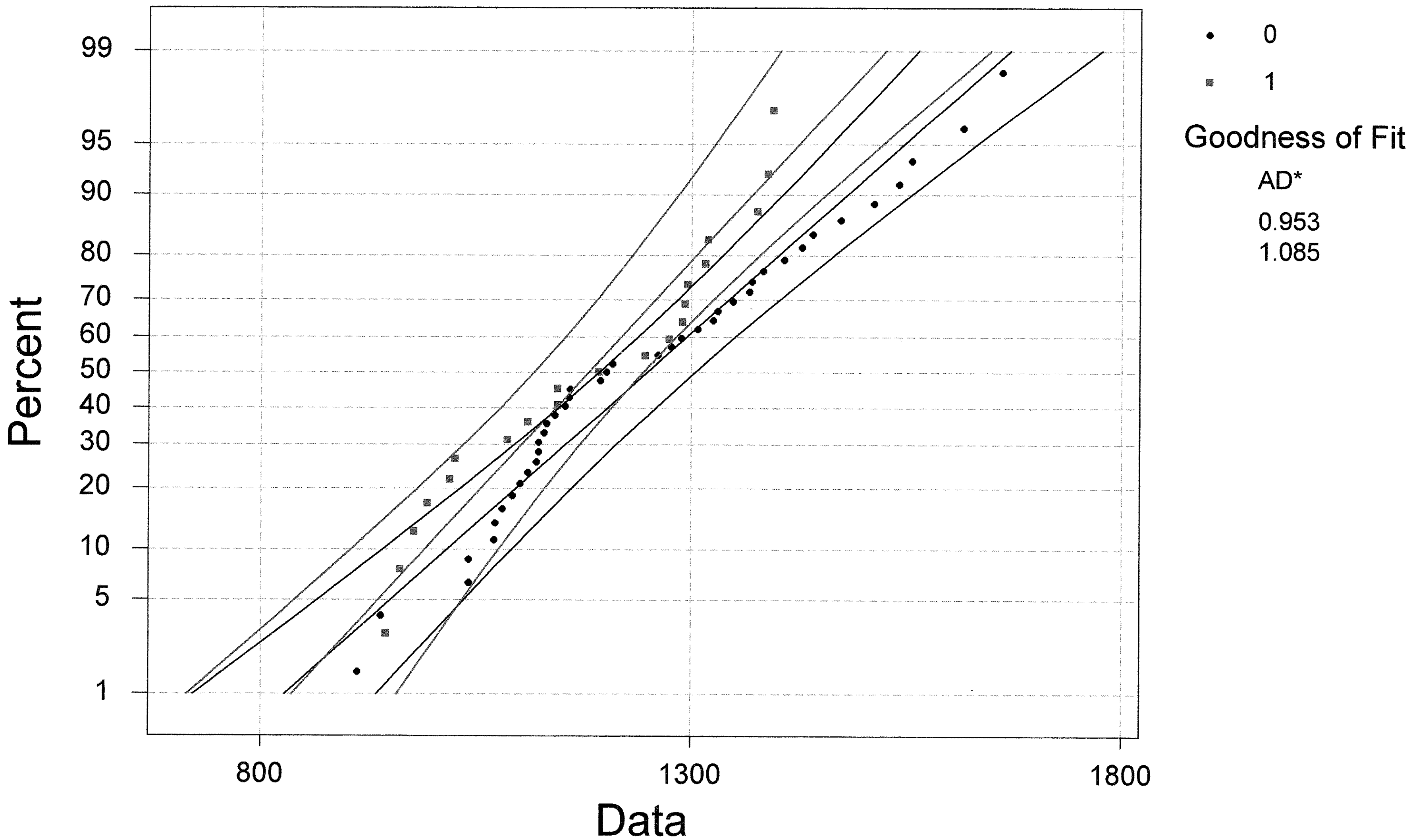
Two-Sample T-Test and CI: QUH mm, THa

```
Two-sample T for QUH  mm

THa          N      Mean     StDev   SE Mean
0           41      1248       183        29
1           21      1180       152        33

Difference = mu (0) - mu (1)
Estimate for difference:  68.0
95% CI for difference: (-20.1, 156.1)
T-Test of difference = 0 (vs not =): T-Value = 1.55  P-Value = 0.127  DF = 47
```

0 = Before 1980
1 = After 1980

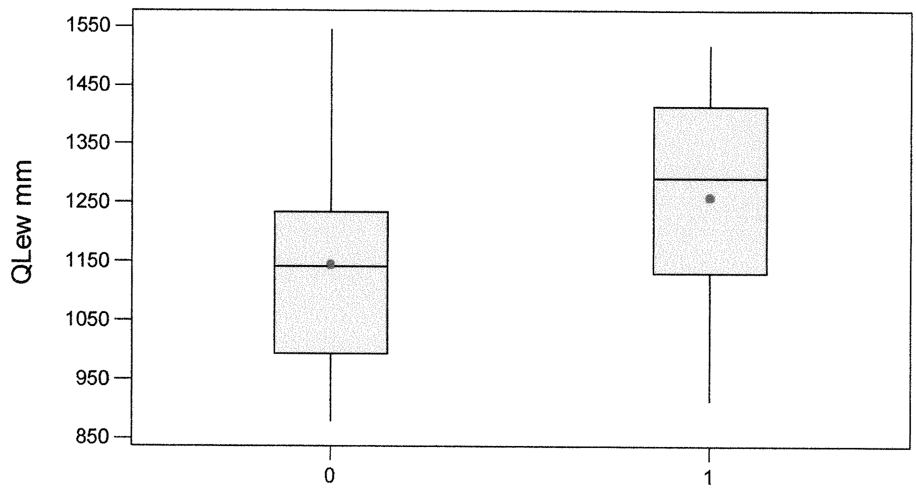
Normal Probability Plot for QUH mm By THa

ML Estimates - 95% CI



Boxplots of QLew mm by THb

(means are indicated by solid circles)

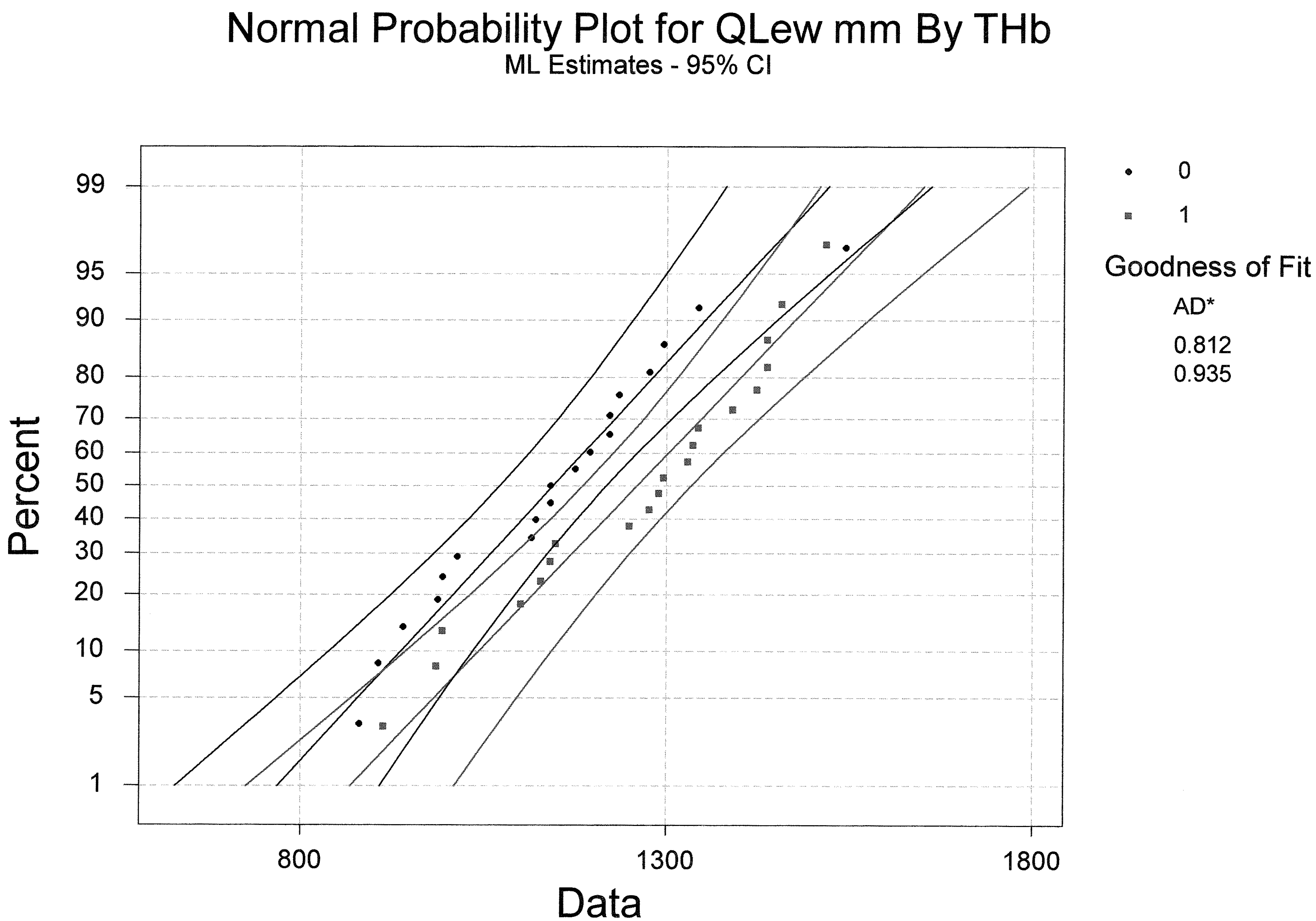


Two-Sample T-Test and CI: QLew mm, THb

```
Two-sample T for QLew mm

THb          N       Mean      StDev    SE Mean
0           19       1145        166         38
1           20       1259        173         39

Difference = mu (0) - mu (1)
Estimate for difference:  -114.9
95% CI for difference: (-225.0, -4.8)
T-Test of difference = 0 (vs not =): T-Value = -2.12  P-Value = 0.041  DF = 36
```

0 = Before 1980

1 = after 1980



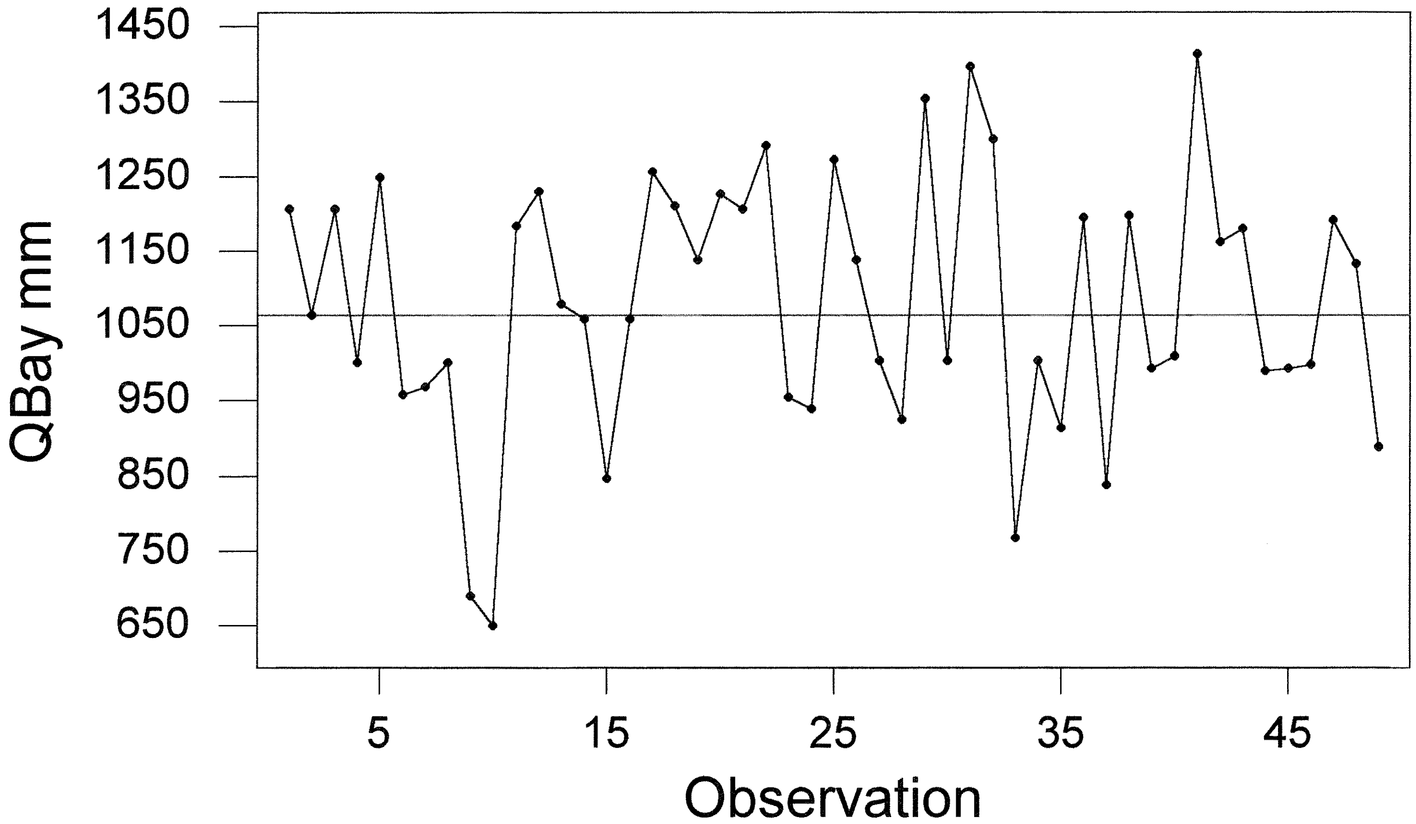
Normal Probability Plot for QLew mm By THb
ML Estimates - 95% CI
Percent
99
95
90
80
70
60
50
40
30
20
10
5
1
800
1300
1800
Data
0
1
Goodness of Fit
AD*
0.812
0.935

G35

Appendix H

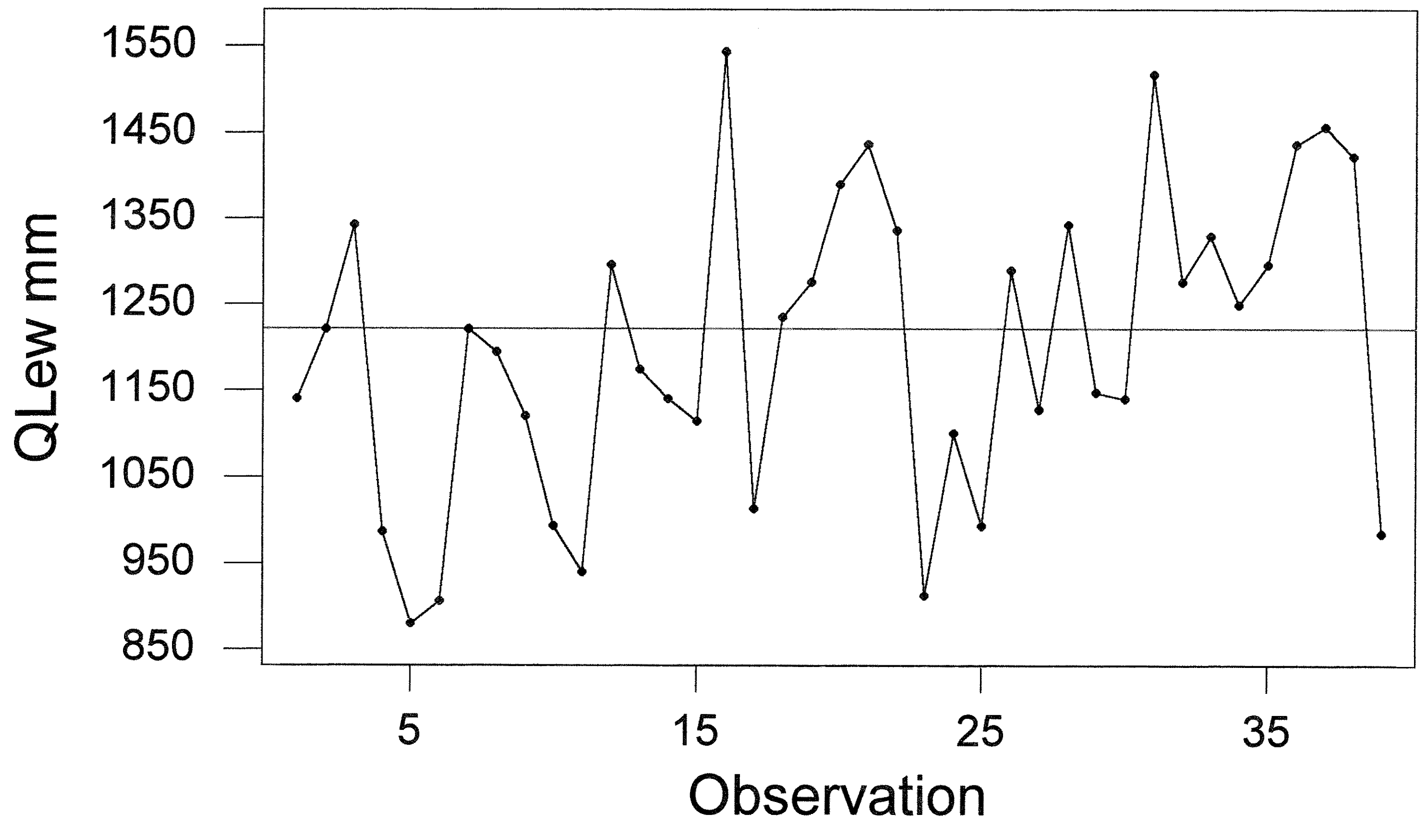
Run Charts

Run Chart for QBay mm



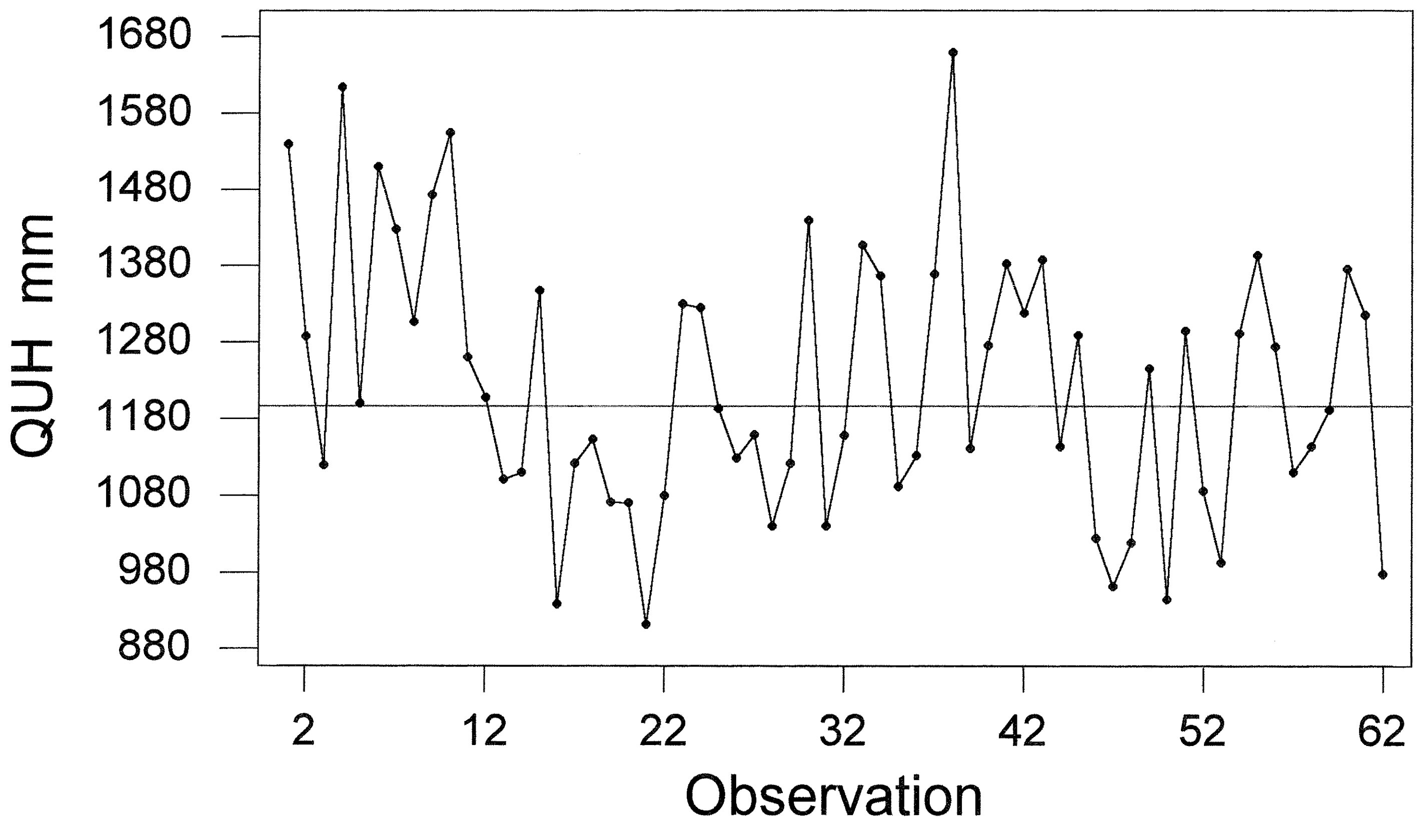
Number of runs about median:	24.0000	Number of runs up or down:	33.0000
Expected number of runs:	25.4898	Expected number of runs:	32.3333
Longest run about median:	6.0000	Longest run up or down:	3.0000
Approx P-Value for Clustering:	0.3335	Approx P-Value for Trends:	0.5910
Approx P-Value for Mixtures:	0.6665	Approx P-Value for Oscillation:	0.4090

Run Chart for QLew mm



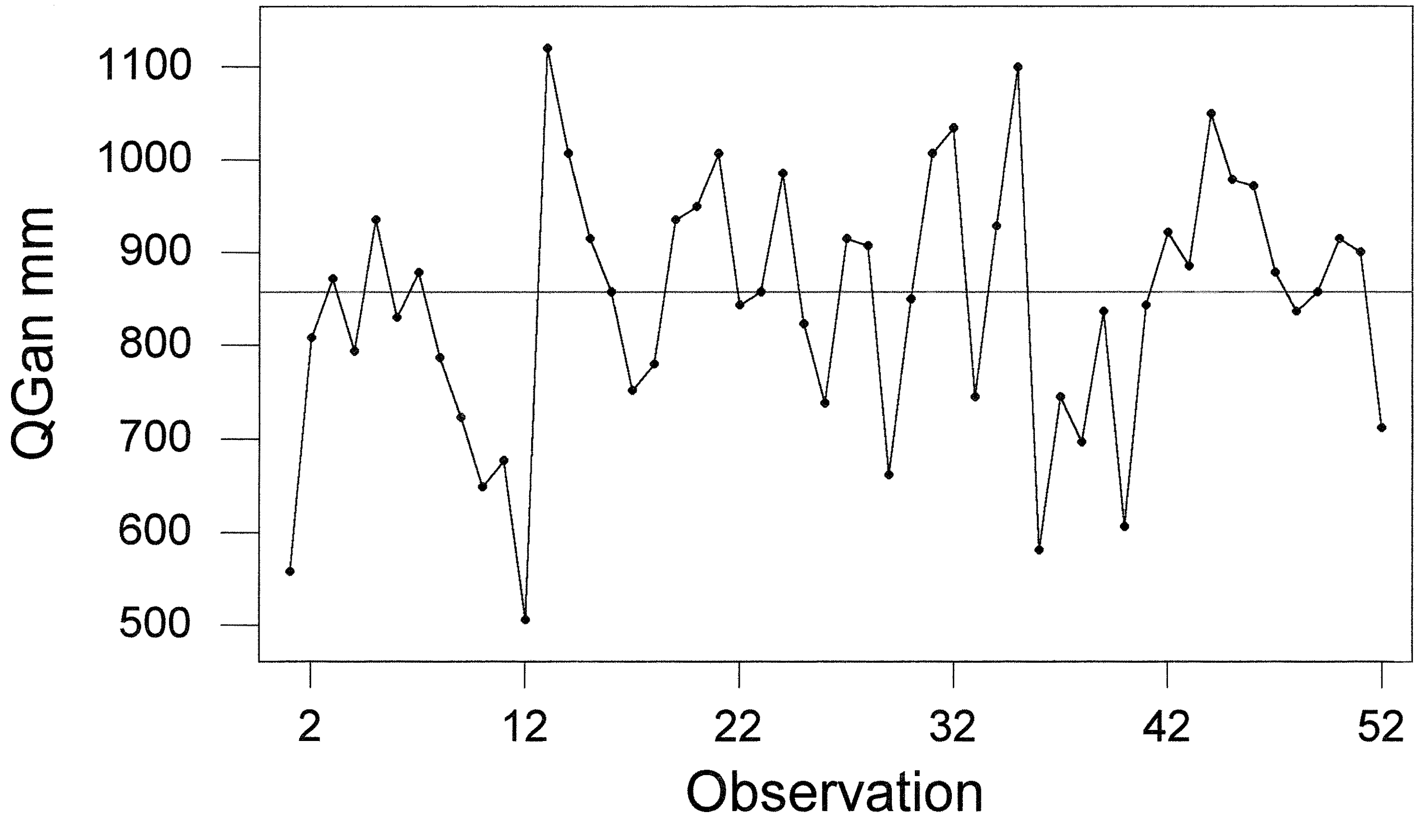
Number of runs about median:	15.0000	Number of runs up or down:	22.0000
Expected number of runs:	20.3846	Expected number of runs:	25.6667
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.0393	Approx P-Value for Trends:	0.0769
Approx P-Value for Mixtures:	0.9607	Approx P-Value for Oscillation:	0.9231

Run Chart for QUH mm



Number of runs about median:	26.0000	Number of runs up or down:	35.0000
Expected number of runs:	32.0000	Expected number of runs:	41.0000
Longest run about median:	9.0000	Longest run up or down:	3.0000
Approx P-Value for Clustering:	0.0622	Approx P-Value for Trends:	0.0333
Approx P-Value for Mixtures:	0.9378	Approx P-Value for Oscillation:	0.9667

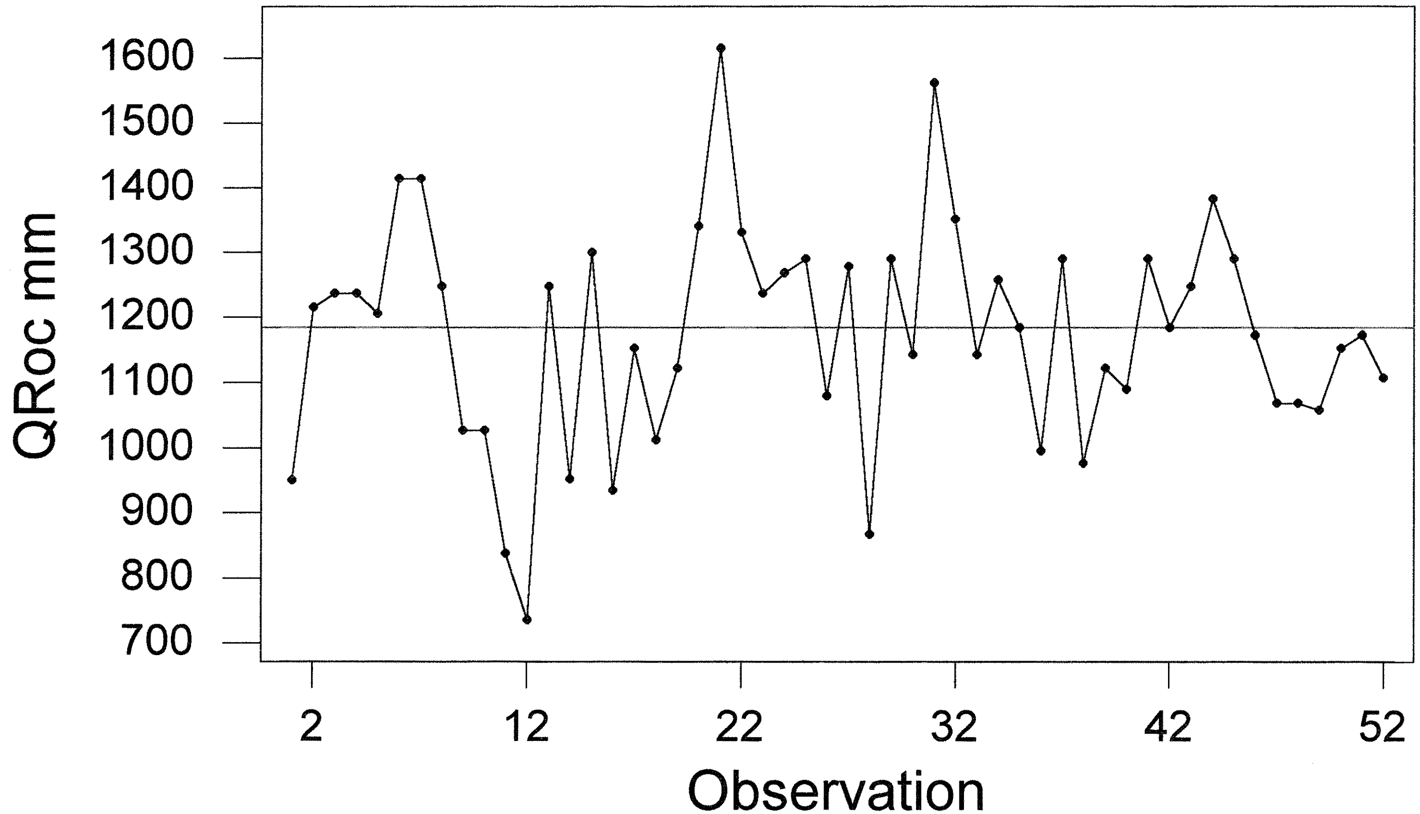
Run Chart for QGan mm



Number of runs about median:	23.0000	Number of runs up or down:	30.0000
Expected number of runs:	26.8462	Expected number of runs:	34.3333
Longest run about median:	6.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1392	Approx P-Value for Trends:	0.0734
Approx P-Value for Mixtures:	0.8608	Approx P-Value for Oscillation:	0.9266

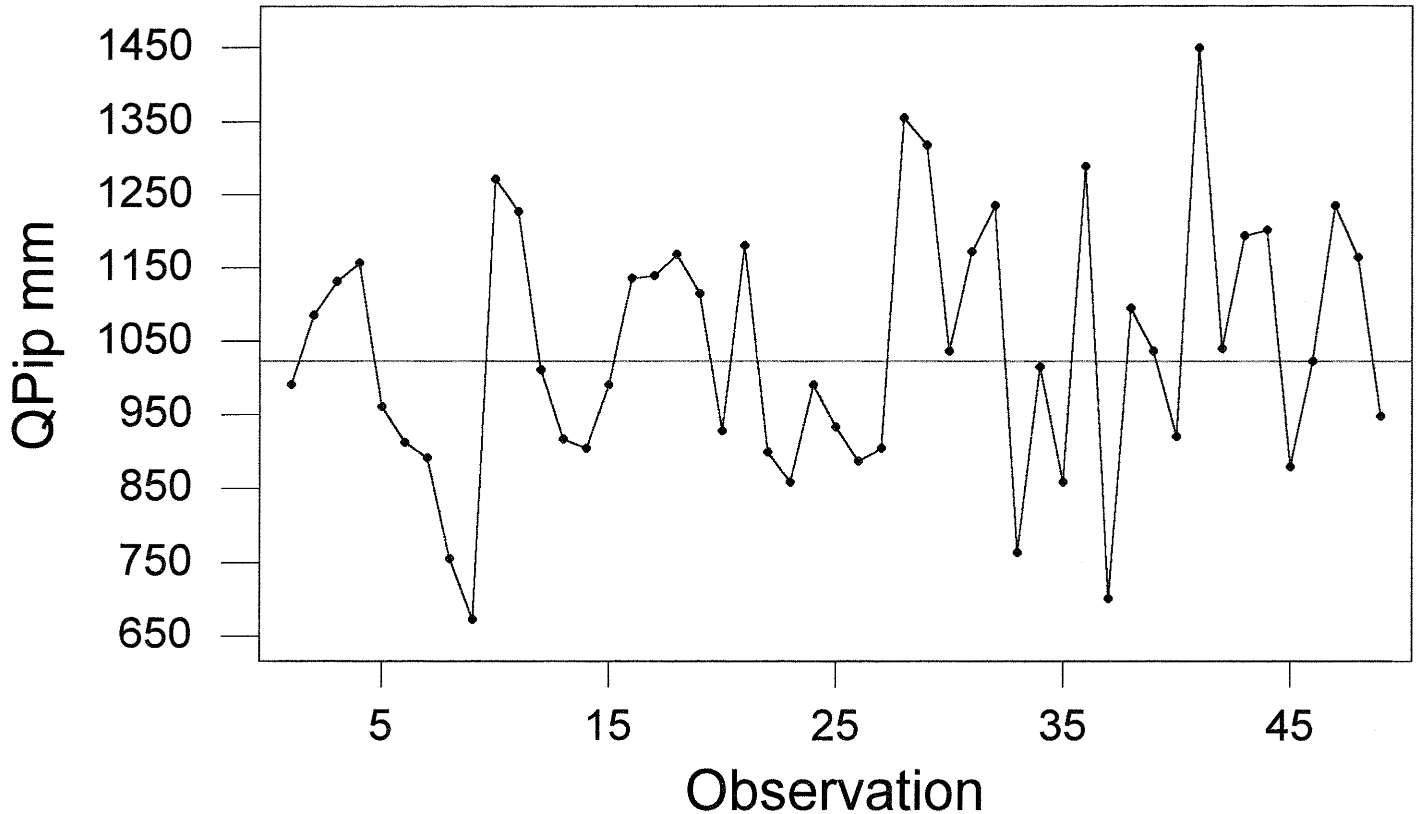
H4

Run Chart for QRoc mm



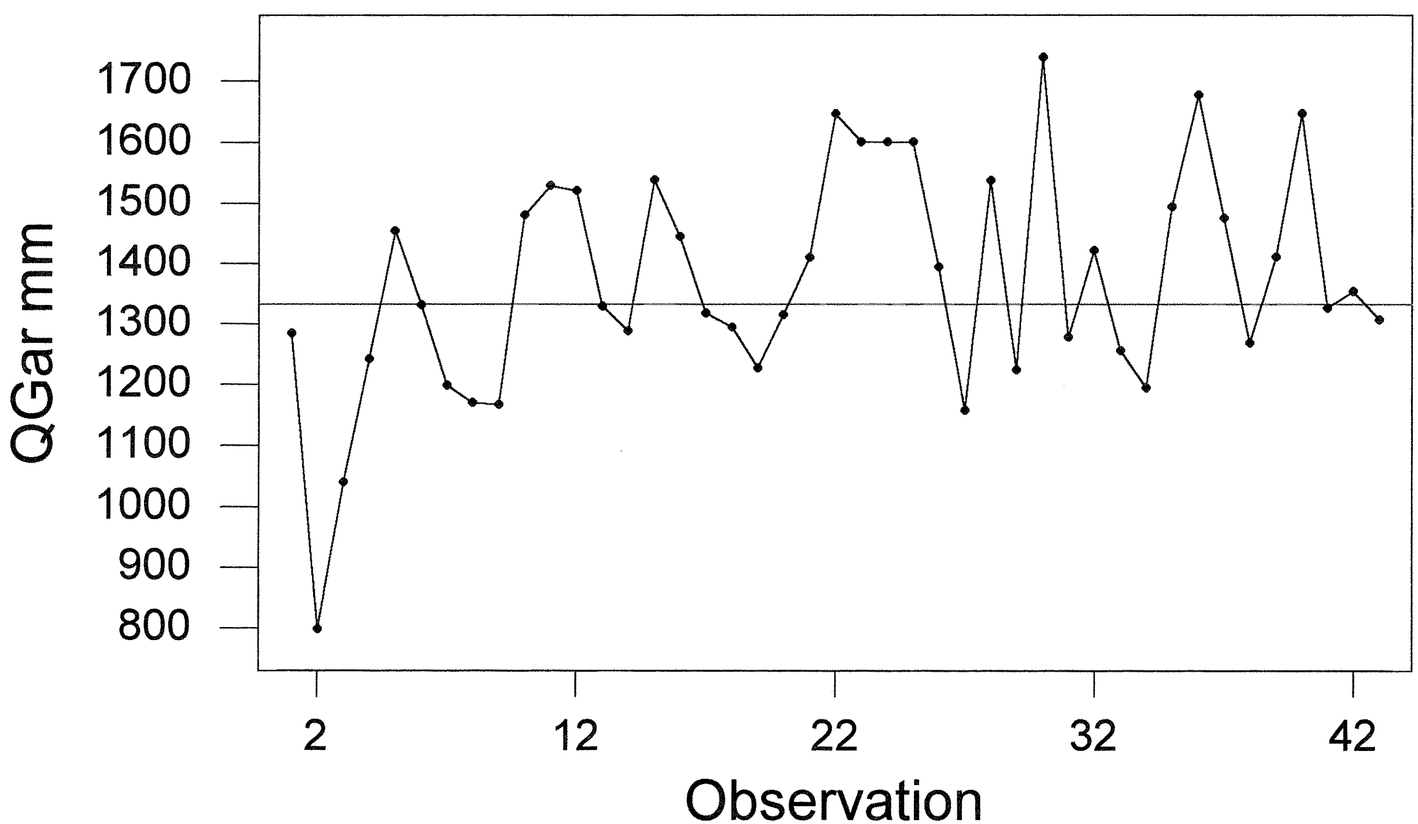
Number of runs about median:	23.0000	Number of runs up or down:	32.0000
Expected number of runs:	26.9615	Expected number of runs:	34.3333
Longest run about median:	7.0000	Longest run up or down:	6.0000
Approx P-Value for Clustering:	0.1332	Approx P-Value for Trends:	0.2174
Approx P-Value for Mixtures:	0.8668	Approx P-Value for Oscillation:	0.7826

Run Chart for QPip mm



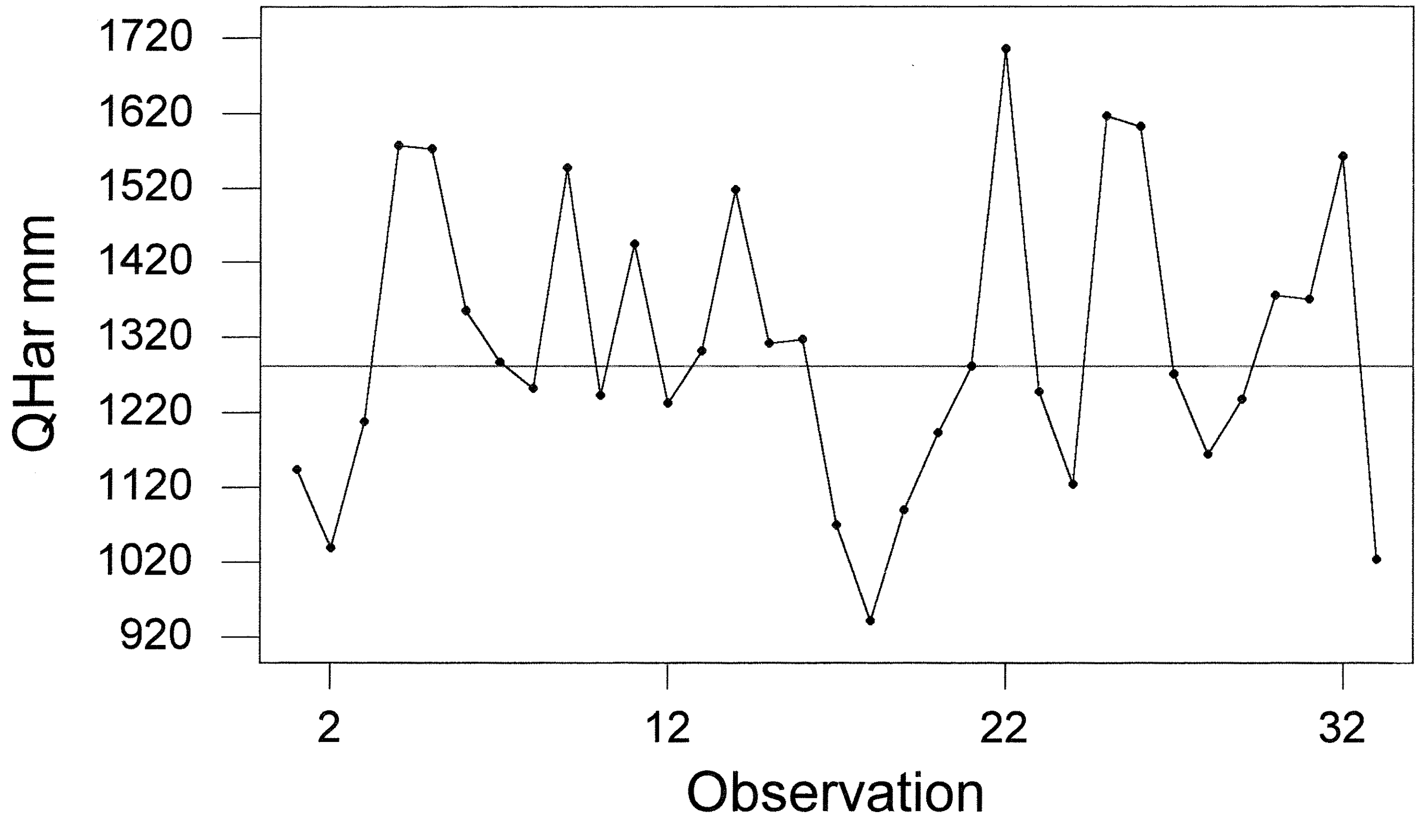
Number of runs about median:	19.0000	Number of runs up or down:	26.0000
Expected number of runs:	25.4898	Expected number of runs:	32.3333
Longest run about median:	6.0000	Longest run up or down:	5.0000
Approx P-Value for Clustering:	0.0304	Approx P-Value for Trends:	0.0144
Approx P-Value for Mixtures:	0.9696	Approx P-Value for Oscillation:	0.9856

Run Chart for QGar mm



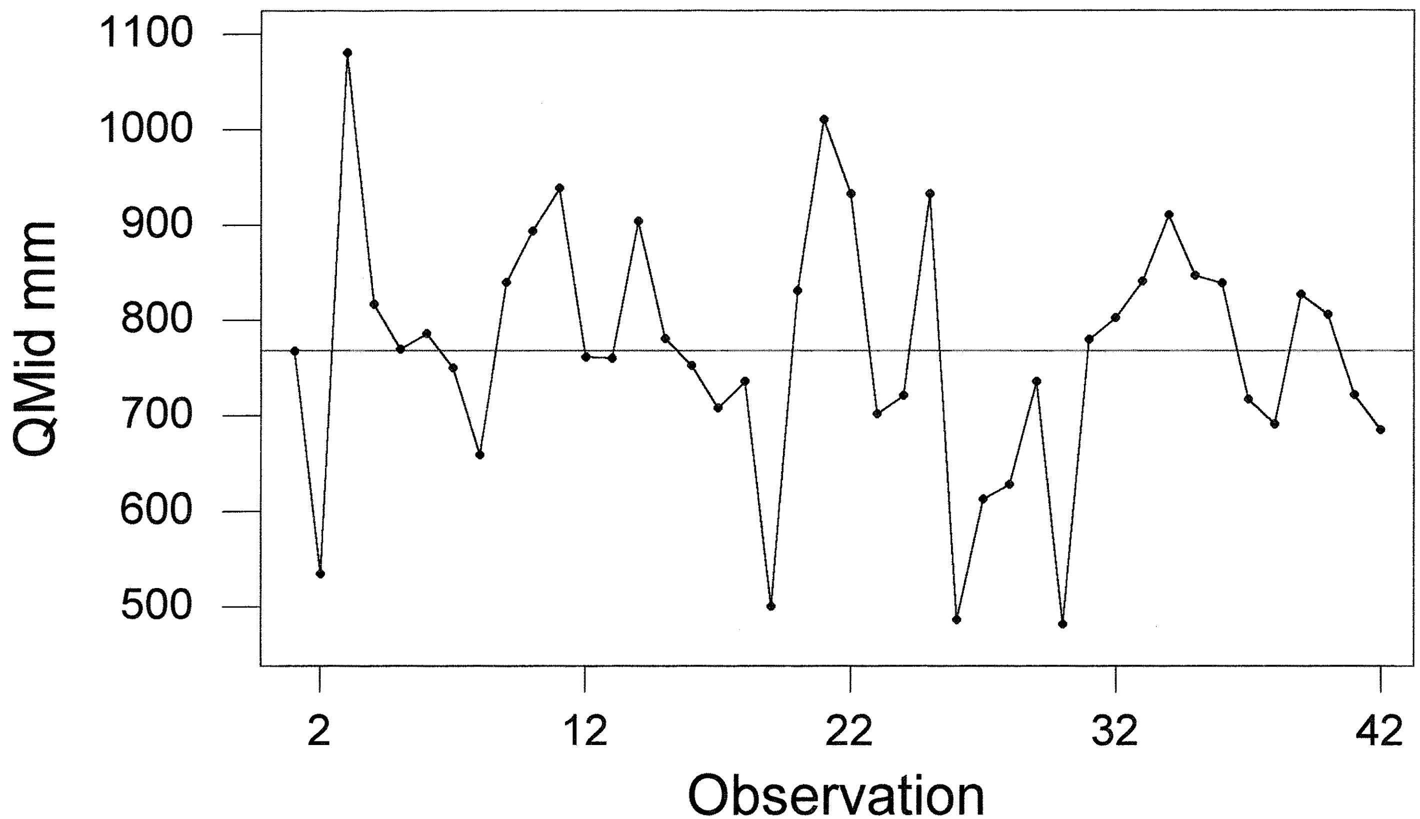
Number of runs about median:	21.0000	Number of runs up or down:	21.0000
Expected number of runs:	22.4884	Expected number of runs:	28.3333
Longest run about median:	6.0000	Longest run up or down:	5.0000
Approx P-Value for Clustering:	0.3229	Approx P-Value for Trends:	0.0034
Approx P-Value for Mixtures:	0.6771	Approx P-Value for Oscillation:	0.9966

Run Chart for QHar mm



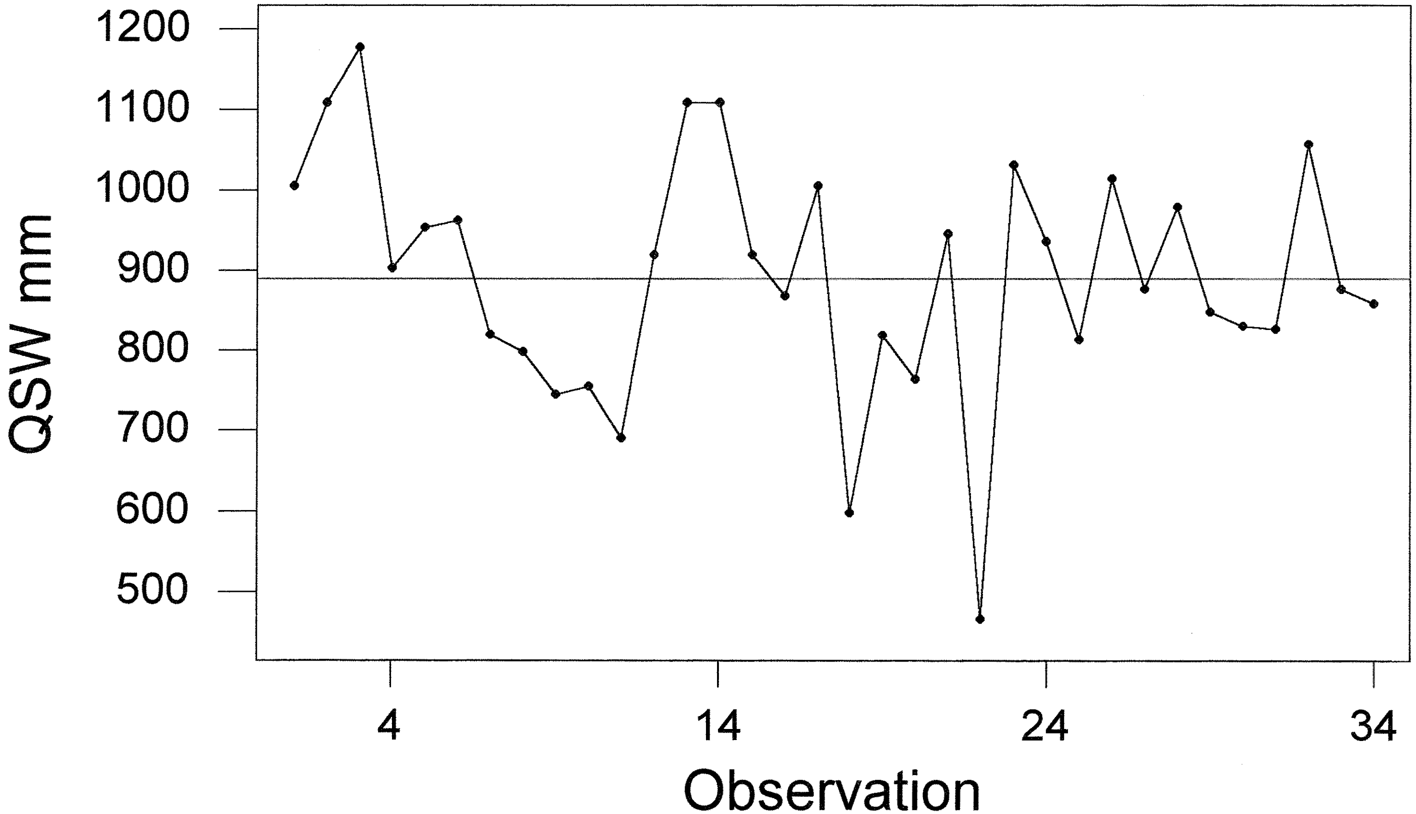
Number of runs about median:	15.0000	Number of runs up or down:	19.0000
Expected number of runs:	17.4848	Expected number of runs:	21.6667
Longest run about median:	5.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1895	Approx P-Value for Trends:	0.1287
Approx P-Value for Mixtures:	0.8105	Approx P-Value for Oscillation:	0.8713

Run Chart for QMid mm



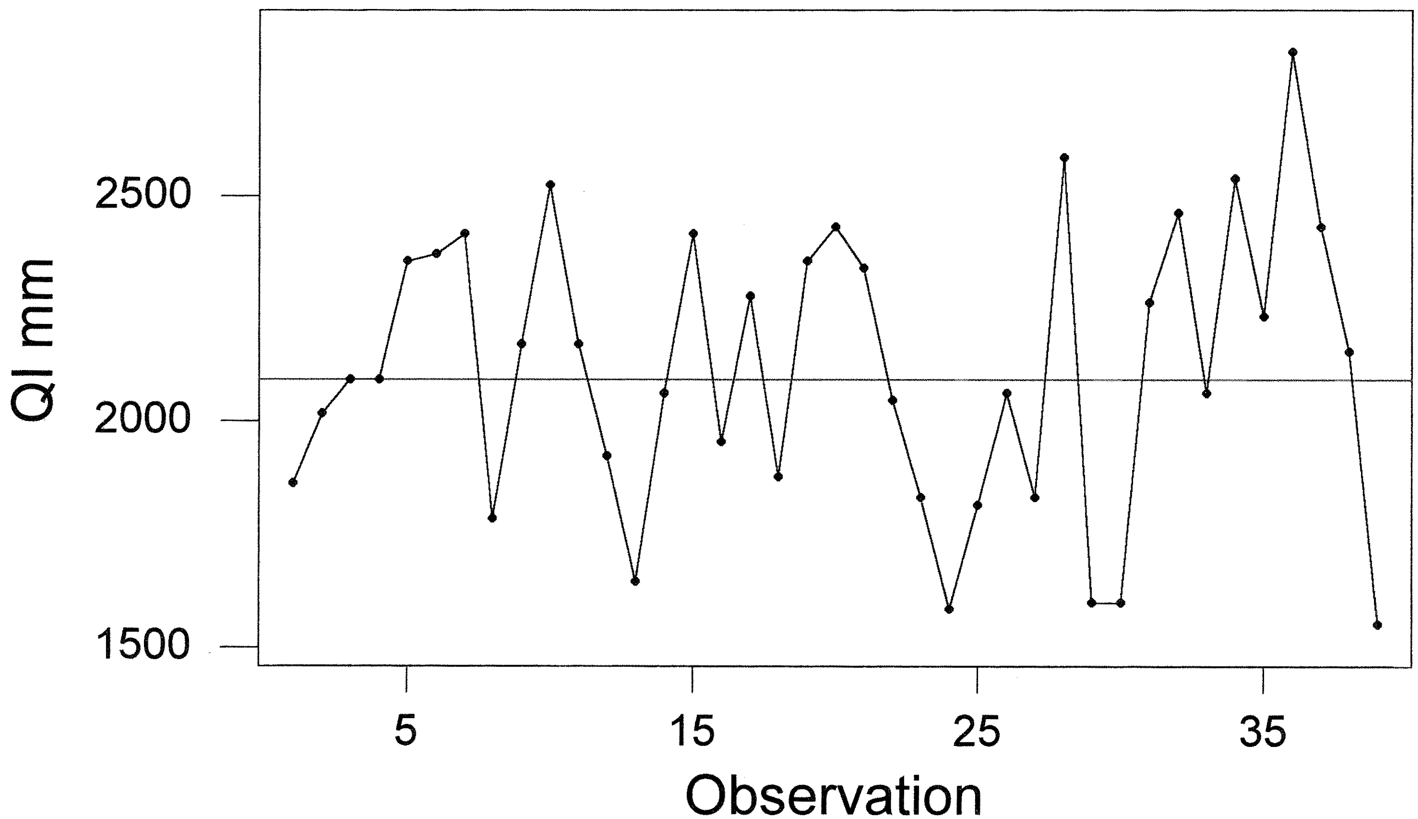
Number of runs about median:	15.0000	Number of runs up or down:	21.0000
Expected number of runs:	22.0000	Expected number of runs:	27.6667
Longest run about median:	6.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.0144	Approx P-Value for Trends:	0.0063
Approx P-Value for Mixtures:	0.9856	Approx P-Value for Oscillation:	0.9937

Run Chart for QSW mm



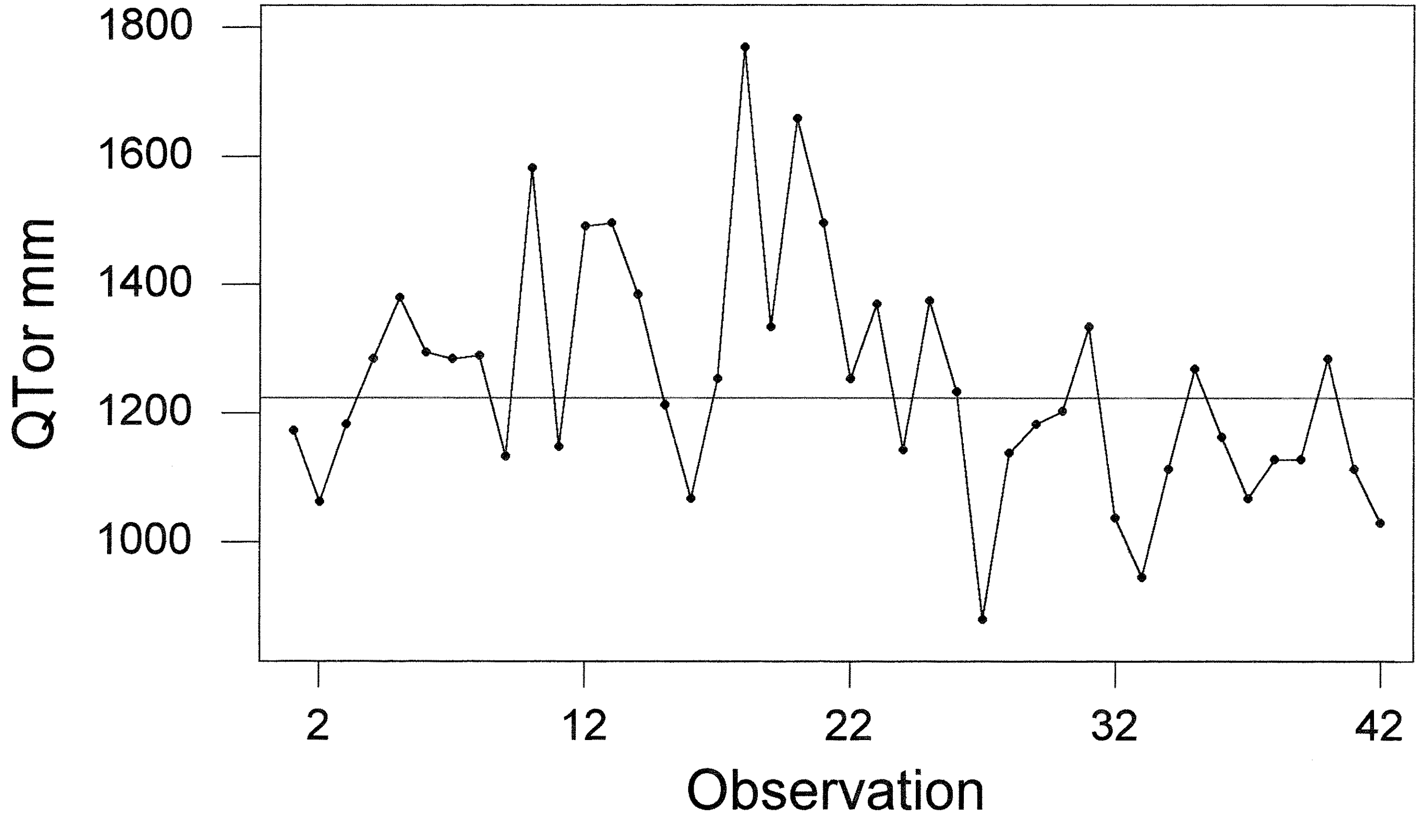
Number of runs about median:	16.0000	Number of runs up or down:	22.0000
Expected number of runs:	18.0000	Expected number of runs:	22.3333
Longest run about median:	6.0000	Longest run up or down:	3.0000
Approx P-Value for Clustering:	0.2430	Approx P-Value for Trends:	0.4446
Approx P-Value for Mixtures:	0.7570	Approx P-Value for Oscillation:	0.5554

Run Chart for QI mm



Number of runs about median:	17.0000	Number of runs up or down:	22.0000
Expected number of runs:	20.4872	Expected number of runs:	25.6667
Longest run about median:	6.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1287	Approx P-Value for Trends:	0.0769
Approx P-Value for Mixtures:	0.8713	Approx P-Value for Oscillation:	0.9231

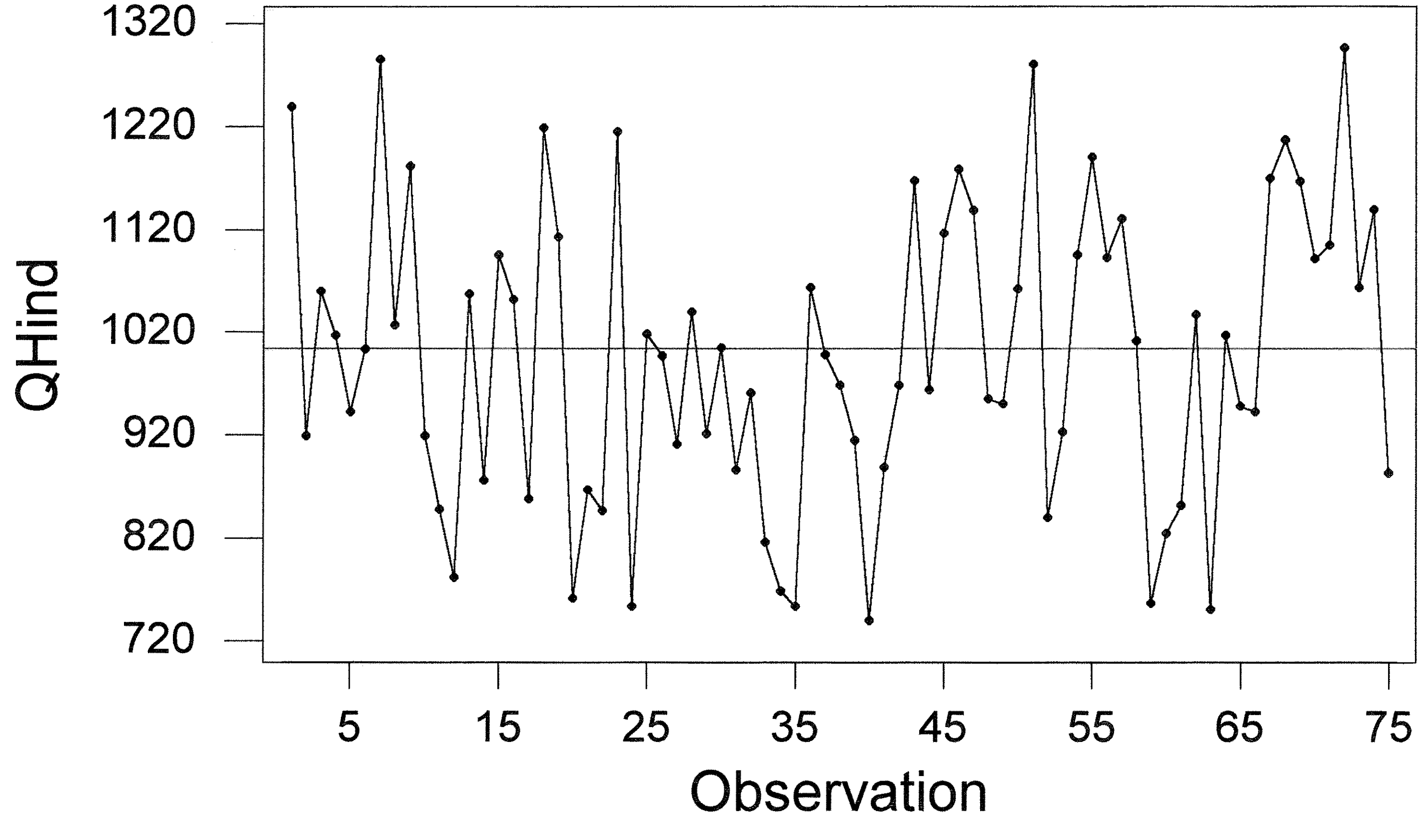
Run Chart for QTor mm



Number of runs about median:	17.0000	Number of runs up or down:	25.0000
Expected number of runs:	22.0000	Expected number of runs:	27.6667
Longest run about median:	7.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.0591	Approx P-Value for Trends:	0.1592
Approx P-Value for Mixtures:	0.9409	Approx P-Value for Oscillation:	0.8408

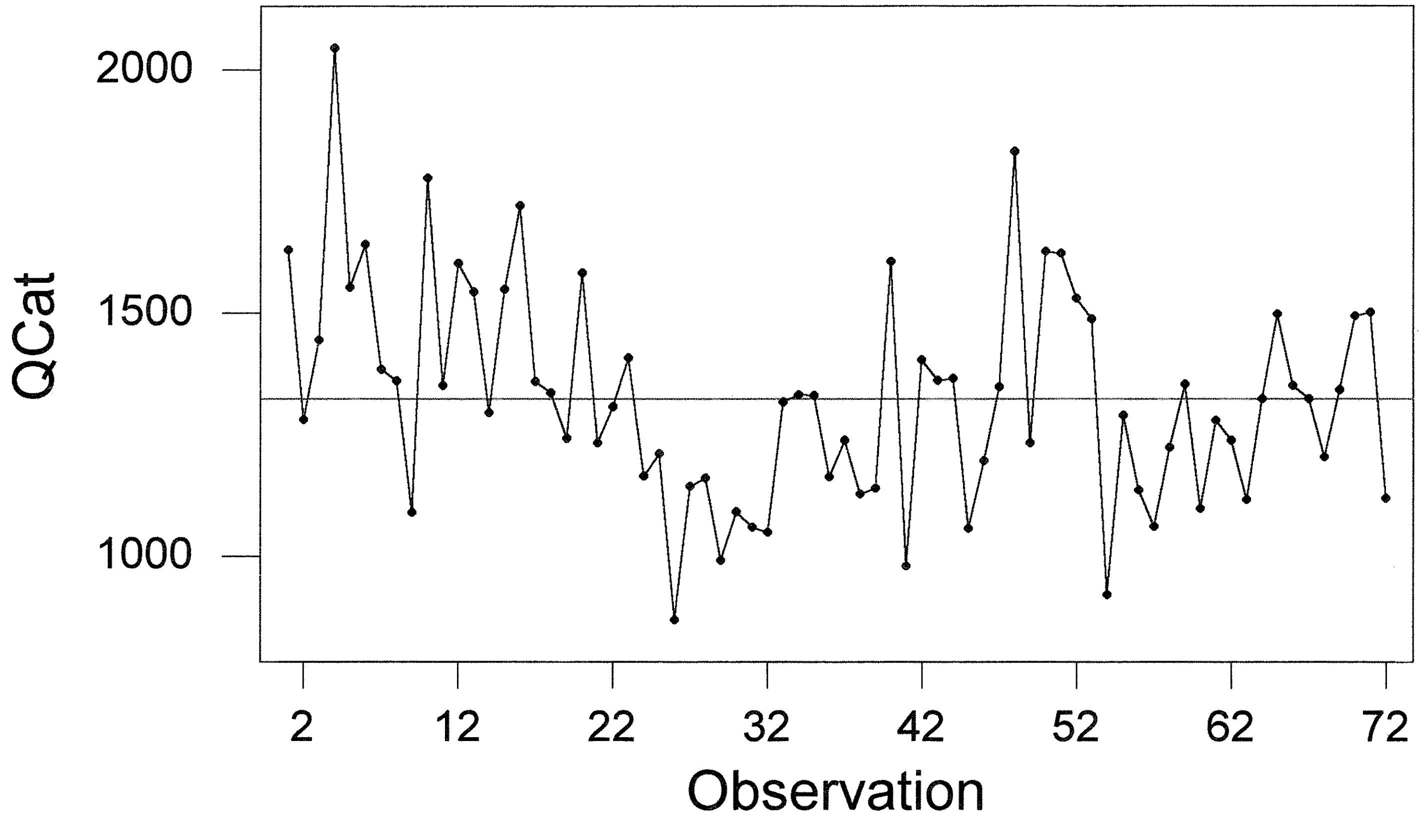
H12

Run Chart for QHind 75 yrs



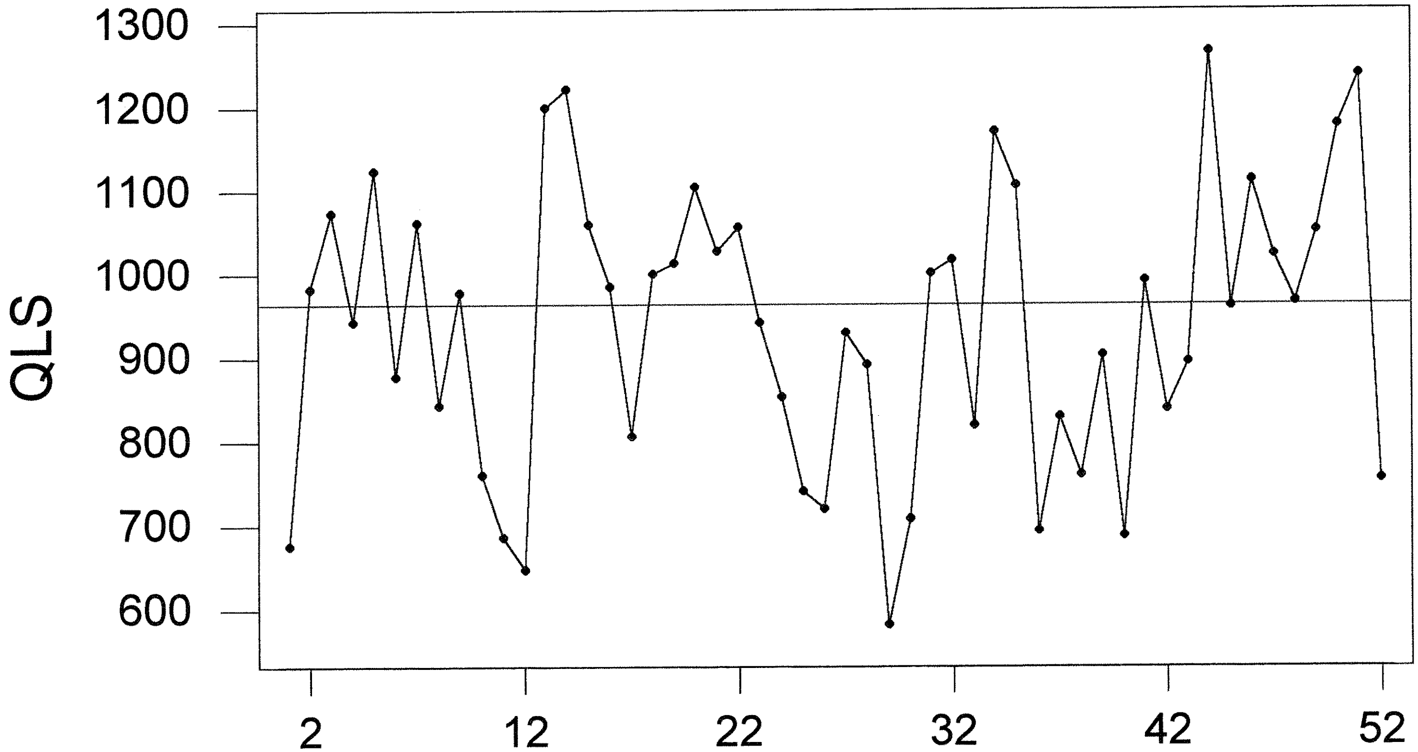
Number of runs about median:	36.0000	Number of runs up or down:	47.0000
Expected number of runs:	38.4933	Expected number of runs:	49.6667
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.2810	Approx P-Value for Trends:	0.2299
Approx P-Value for Mixtures:	0.7190	Approx P-Value for Oscillation:	0.7701

Run Chart for QCat 72 yrs



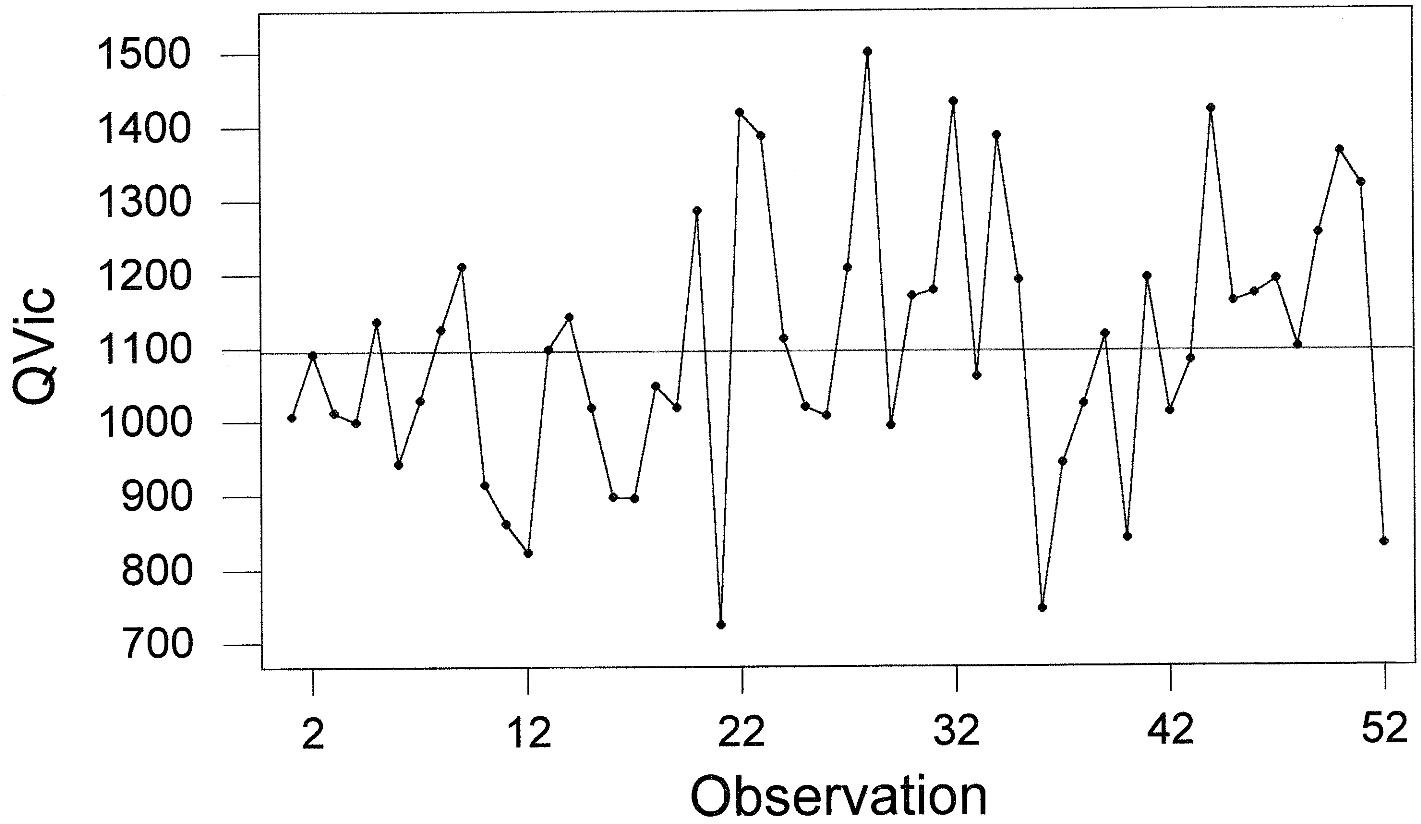
Number of runs about median:	28.0000	Number of runs up or down:	45.0000
Expected number of runs:	36.9722	Expected number of runs:	47.6667
Longest run about median:	10.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.0165	Approx P-Value for Trends:	0.2251
Approx P-Value for Mixtures:	0.9835	Approx P-Value for Oscillation:	0.7749

Run Chart for QLS



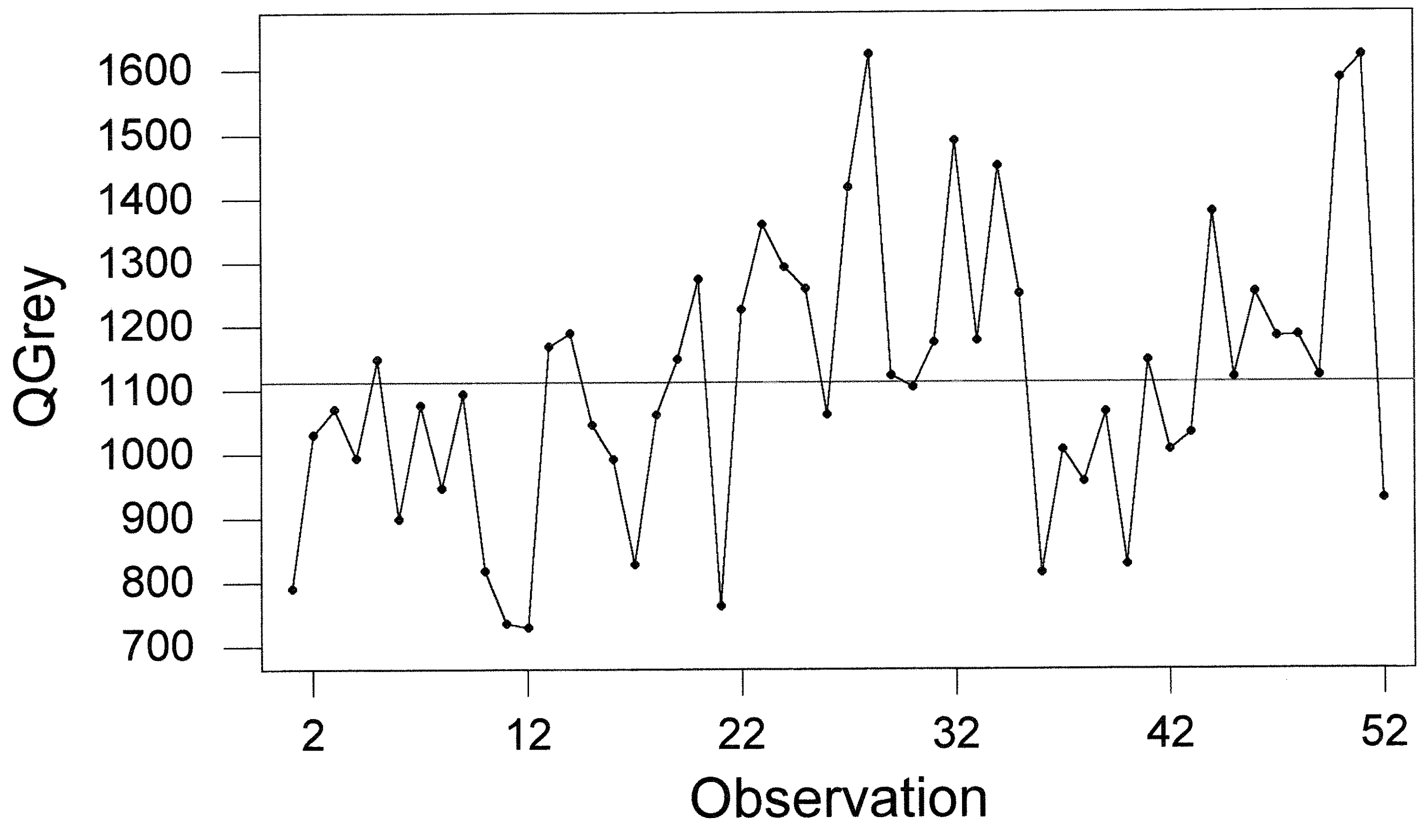
Number of runs about median:	23.0000	Number of runs up or down:	32.0000
Expected number of runs:	27.0000	Expected number of runs:	34.3333
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1313	Approx P-Value for Trends:	0.2174
Approx P-Value for Mixtures:	0.8687	Approx P-Value for Oscillation:	0.7826

Run Chart for QVic



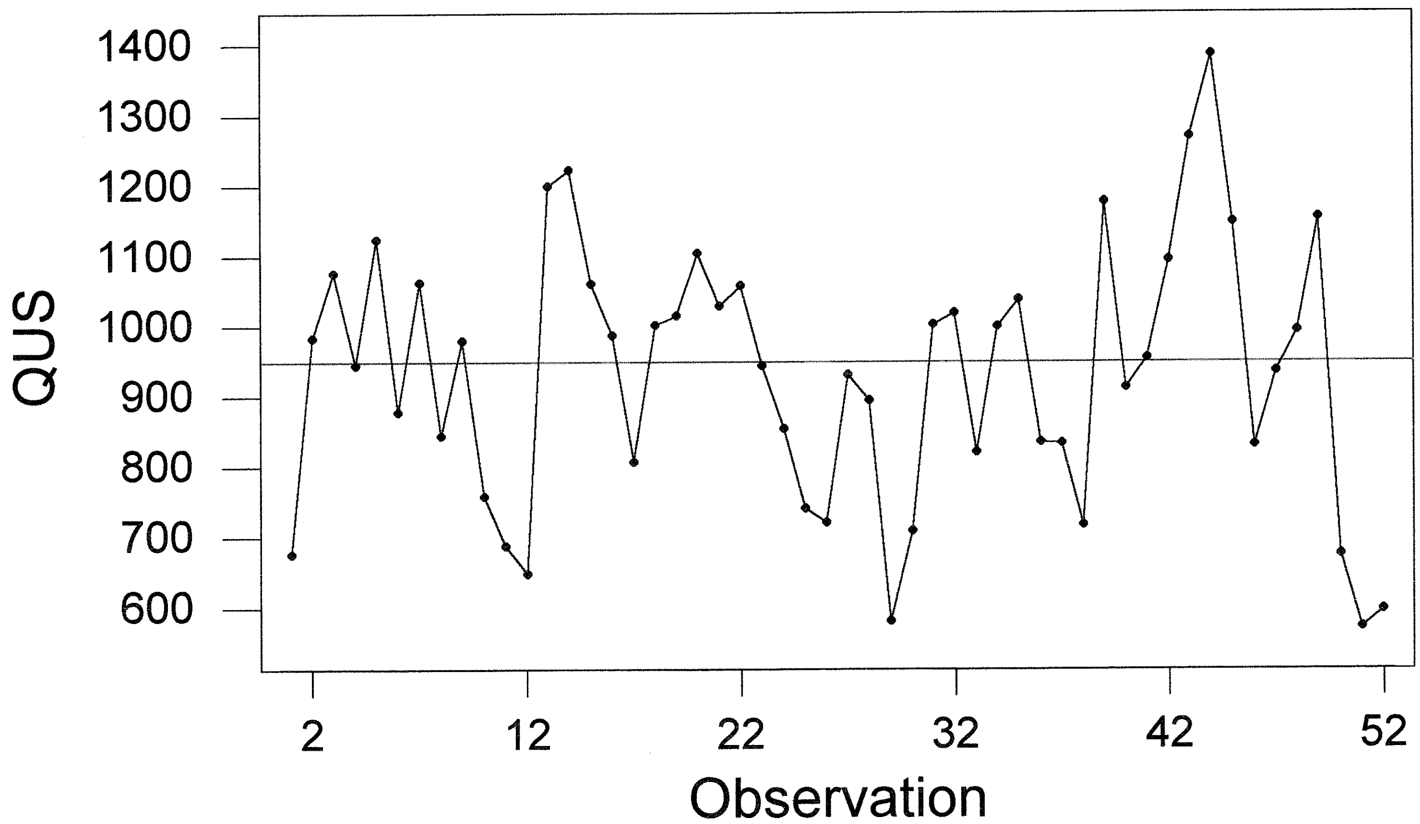
Number of runs about median:	23.0000	Number of runs up or down:	30.0000
Expected number of runs:	27.0000	Expected number of runs:	34.3333
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1313	Approx P-Value for Trends:	0.0734
Approx P-Value for Mixtures:	0.8687	Approx P-Value for Oscillation:	0.9266

Run Chart for QGrey



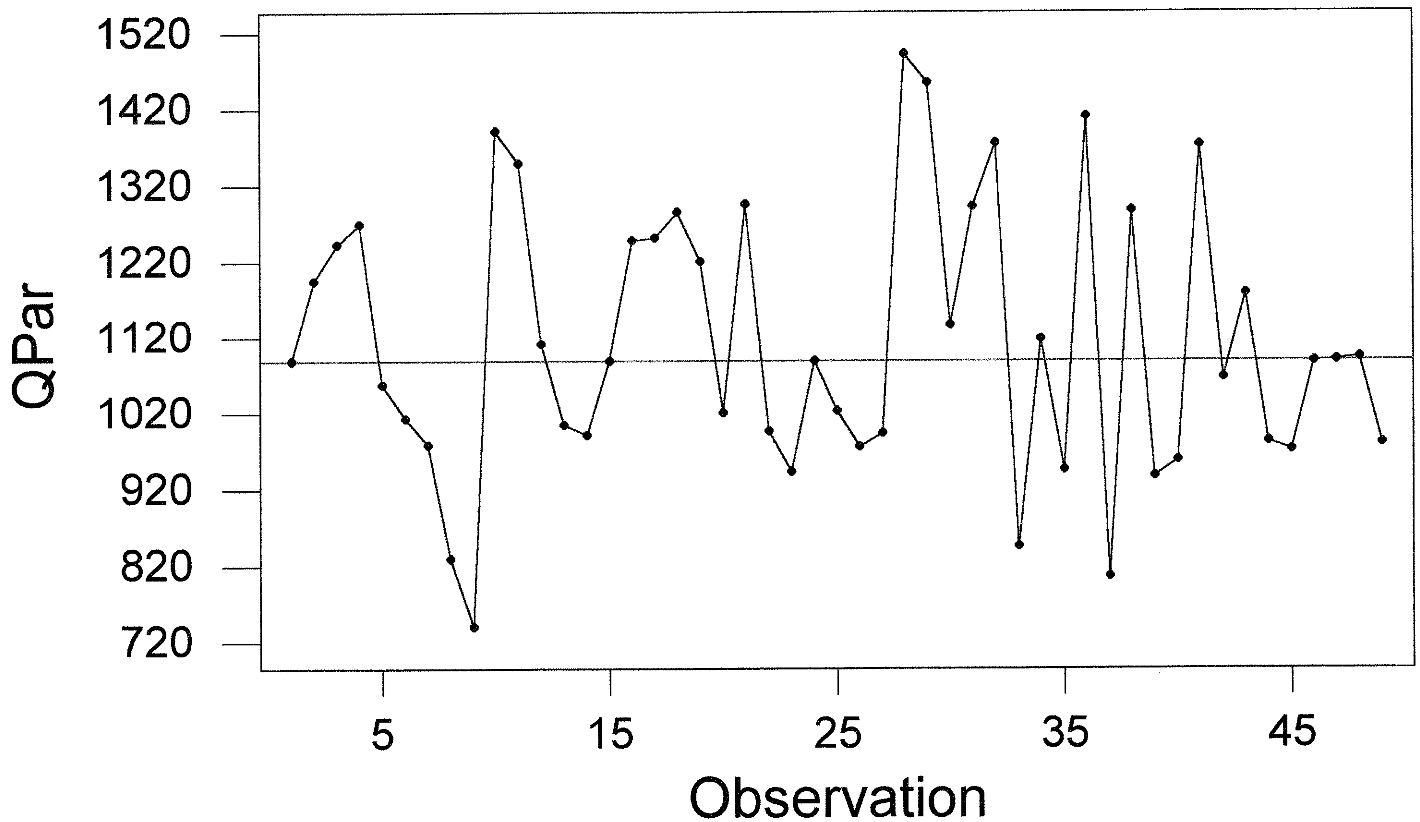
Number of runs about median:	17.0000	Number of runs up or down:	34.0000
Expected number of runs:	27.0000	Expected number of runs:	34.3333
Longest run about median:	8.0000	Longest run up or down:	3.0000
Approx P-Value for Clustering:	0.0025	Approx P-Value for Trends:	0.4556
Approx P-Value for Mixtures:	0.9975	Approx P-Value for Oscillation:	0.5444

Run Chart for QUS



Number of runs about median:	23.0000	Number of runs up or down:	27.0000
Expected number of runs:	27.0000	Expected number of runs:	34.3333
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1313	Approx P-Value for Trends:	0.0070
Approx P-Value for Mixtures:	0.8687	Approx P-Value for Oscillation:	0.9930

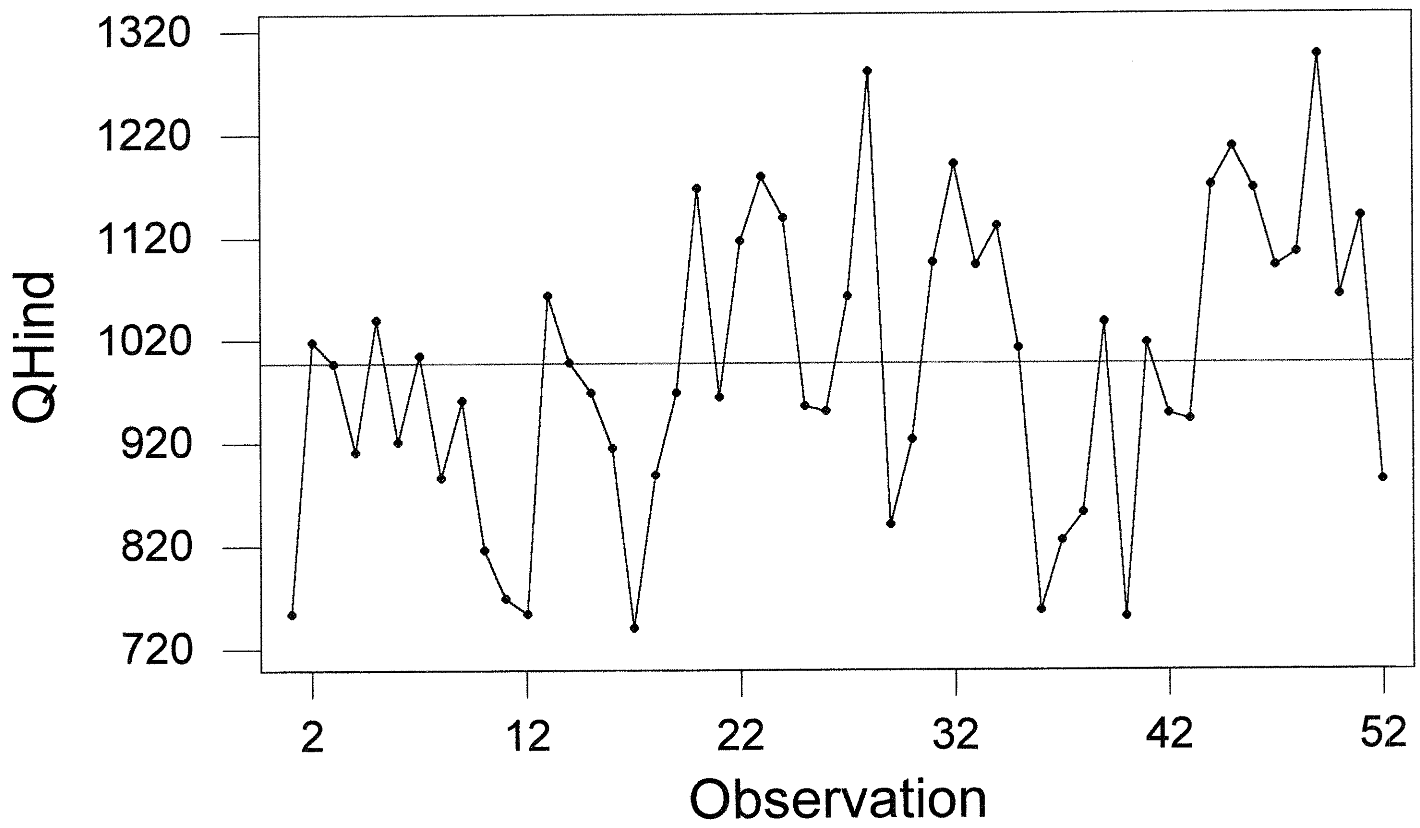
Run Chart for QPar



Number of runs about median:	23.0000
Expected number of runs:	25.4082
Longest run about median:	6.0000
Approx P-Value for Clustering:	0.2426
Approx P-Value for Mixtures:	0.7574

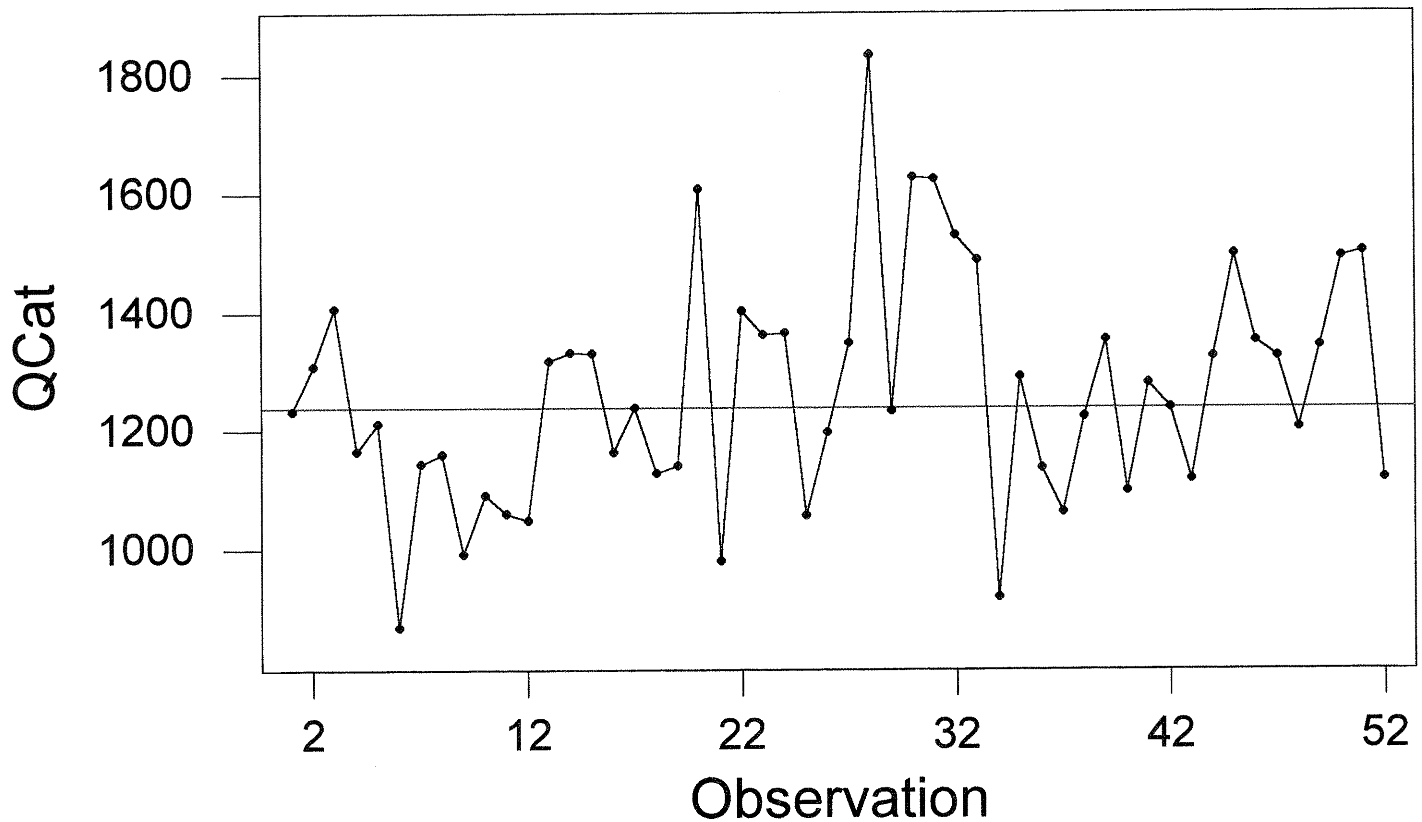
Number of runs up or down:	26.0000
Expected number of runs:	32.3333
Longest run up or down:	5.0000
Approx P-Value for Trends:	0.0144
Approx P-Value for Oscillation:	0.9856

Run Chart for QHind



Number of runs about median:	23.0000	Number of runs up or down:	30.0000
Expected number of runs:	27.0000	Expected number of runs:	34.3333
Longest run about median:	8.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1313	Approx P-Value for Trends:	0.0734
Approx P-Value for Mixtures:	0.8687	Approx P-Value for Oscillation:	0.9266

Run Chart for QCat



Number of runs about median:	23.0000	Number of runs up or down:	32.0000
Expected number of runs:	26.9615	Expected number of runs:	34.3333
Longest run about median:	9.0000	Longest run up or down:	4.0000
Approx P-Value for Clustering:	0.1332	Approx P-Value for Trends:	0.2174
Approx P-Value for Mixtures:	0.8668	Approx P-Value for Oscillation:	0.7826

Appendix I

Climate Change Annotated References

I - Review of Selected Climate Change Literature

I.1 Government of Canada Publications

***Climate Change Impacts and Adaptations: A Canadian Perspective – Water Resources* (one chapter of a document in progress), Government of Canada, July 2002.**

This report is a summary of current knowledge on climate change in Canada. The introduction states "Climatic variables, such as temperature and precipitation, greatly influence the hydrological cycle, and changes in these variables will affect runoff and evaporation patterns, as well as the amount of water stored in glaciers, snowpacks, lakes, wetlands, soil moisture and groundwater. However, there remains uncertainty as to the magnitude and in some cases, the direction of these changes. This is related to the difficulty that climate models have in projecting future changes in regional precipitation patterns and extreme events, and to our incomplete understanding of hydroclimatic processes."

Table 2 of the Water Resources chapter provides a list of potential impacts of climate change on water resources in regions across Canada. Changes and concerns listed for the Atlantic Region are reproduced in the table below.

Potential Changes	Associated Concerns
Decreased amount and duration of snow cover	Smaller spring floods, lower summer flows
Changes in the magnitude and timing of ice freeze-up and break-up	Implications for spring flooding and coastal erosion
Possible large reductions in streamflow	Ecological impacts, water apportionment issues, hydroelectric potential
Saline intrusion into coastal aquifers	Loss of potable water and increased water conflicts

Of these effects, changes in snow cover and in streamflow have the potential to impact NLH's hydroelectric generation.

In the discussion on adaptation in the water resources sector, the report indicates that "studies have shown water managers to be complacent toward the impacts of climate change… This may be because managers generally believe that the tools currently used to deal with risk and uncertainty will be sufficient for dealing with any increased variability induced by climate change." Other researchers point out that uncertainty with respect to climate change is no greater than other uncertainty faced by managers and therefore "uncertainty should not preclude the inclusion of climate change as part of an integrated risk management strategy."

***Canada Country Study: Climate Impacts and Adaptation – Volume VIII: National Sectoral Volume - Energy Sector*, Gilles Mercier.**

This report discusses a range of issues related to climate change and energy including all energy sources, and issues on both the supply and demand sides.

The report suggests that according to global climate scenarios, runoff could be reduced by 20% in the Maritimes, but increase up to 35% in Labrador. The summary table suggests a decrease in runoff on the island of Newfoundland also, but no percentage is given. With specific reference to hydroelectric generation the report says "One response to climate change by hydroelectric managers could include better management of reservoirs…. Efficient storage management in areas of reduced precipitation could optimize the generation of electricity while managing other needs for water resources… Models for forecasting hydrological changes and managing their impacts could play a greater role in the future."

***A Matter of Degrees: A Primer on Climate Change, Environment Canada*, 1997.**

The discussion on impacts on energy supply and demand indicates that there may be increased variability from year to year and an overall increase in generation in Labrador, but a decrease elsewhere. The increased variability in output may lead to a need for additional backup generating sources.

***Water Sector: Vulnerability and Adaptation to Climate Change*, Final Report, 2000, prepared by Global Change Strategies International Inc and the Meteorological Service of Canada.**

This report summarizes discussions at a series of regional workshops. There is only a brief discussion of impacts to hydroelectric generation.

The Canada Country Study: Climate Impacts and Adaptation – Atlantic Canada Summary.

This report is a very general discussion of the potential for climate change in the region. There is nothing of relevance to our study.

I.2 Technical Papers

***Climate Change: Implications for Canadian Water Resources and Hydropower Production*, Yves Filion, Canadian Water Resources Journal, Vol. 25, No. 3, 2000.**

This paper reviews previous studies that considered changes to hydrology resulting from climate change and interprets them in terms of hydropower production. There is a general discussion of changes in energy and extreme events, but nothing specific to Newfoundland. The general conclusion is that hydroelectric stations in northern regions of Canada will see increased generation and that stations in the south will see a significant decrease. A generic list of strategies that utilities could adopt to adapt to changing climate, including both physical and operational measures, is provided.

***Sensitivity of Hydrologic Systems to Climate Change*, Ivan Muzik, Canadian Water Resources Journal, Vol 26, No. 2 2001.**

This paper examines the implication of changes in storm rainfall on flood frequencies and the resulting implication on spillway design. Impacts on generation are not considered.

***Climate Change and Hydropower Generation*, P.J. Robinson, International Journal of Climatology, Vol. 17, 983-996 1997.**

This study looks at the impacts of climate change on the storage required for hydro systems in south eastern US, considering both changes in inflow and changes in demand. The main focus was on the requirements for daily peaking. The study found that there would be increased drawdown in reservoirs, resulting in more variable and less overall generation.

***Climate Change Impacts on the Reliability of Hydroelectric Energy Production*. Mimikou and Baltas, Hydrological Sciences 42(5) October 1997.**

This study considers the risk of not meeting demand under climate change through the use of a case study of a large multipurpose reservoir in northern Greece. The study concludes that under the climate change scenarios examined, increases in storage of up to 50% is required to maintain the same reliability as the original design condition.

***Sensitivity of Mountain Runoff and Hydro-electricity to Changing Climate,* C.E. Garr and B.B. Fitzharris, in *Mountain Environments in Changing Climates*, edited by Martin Beniston, Routledge, 1994.**

This paper considers the impact of climate change on hydroelectric generation in New Zealand and concludes that there will be overall less variability in runoff, making the system less vulnerable. In this instance, climate change also led to reduced demand.

***Modelling the Potential Effects of Climate Change on the Grande Dixence Hydro-Electricity Scheme, Switzerland*, R. Westaway, Water and Environmental Management, Vol. 14, No. 3, 2000.**

This study examined the impact of climate change on a glacier fed hydroelectric power scheme in Switzerland. An increase in temperature and precipitation anticipated under climate change would lead to increased streamflow and therefore the potential for increased generation. For the situation studied, because of the distribution of the additional runoff, physical measures to increase storage would be required to make use of the additional streamflow.

Appendix J

Sample Average Energy Calculation

2000 Hydroelectric Plant Average Energy

	Bay D'Espoir	Upper Salmon	Cat Arm	Hinds Lake	Paradise River
Inflows					
Average Inflow	6,113.39	4,425.43	841.83	651.36	532.40
Less: Turbine Use Adjustment	3.47	6.31	-0.54	-0.06	1.30
Adjusted Inflow	6109.92	4419.12	842.37	651.42	531.11
Average Spill					
Salmon River	14.94				
Upper Salmon*		18.21			
Burnt Pond	31.03	31.03			
Victoria Lake	1.98	1.98			
Subtotal	47.95	51.22	22.60	1.76	117.00
Average Fisheries Compensation					
West Salmon		61.60			
Grey Reservoir (Pudops)	11.84	11.84			
Burnt Pond (White Bear River)	20.52	20.52			
Subtotal	32.36	93.96		14.54	
Results					
Useful Outflow	6029.60	4273.93	819.77	635.12	414.11
Conversion Factor	0.4330	0.1296	0.8972	0.5370	0.0913
Average Energy	*2,611*	*554*	*735*	*341*	*38*
GRAND TOTAL	*4,279*				

1. * Upper Salmon actual spill reduced by 171.31MCM in 1999 due to energy stored in 19!

2. In 1998 the amount of spill in Cat Arm was reduced by 10.20MCM as it was caused by energy stored for customers.

3. In 1999 the amount of spilled water was reduced as there was a significant amount of stored energy for customers carried over from 1998. Salmon River was reduced by 73.67MCM, Cat Arm by 119.96MCM and Hinds Lake by 3.99MCM.

This sheet is used to determine average spills

Year	Salmon River	Cat Arm	Hinds Lake	Paradise River
1975	2.94	n/a	n/a	n/a
1976	2.94	n/a	n/a	n/a
1977	2.94	n/a	n/a	n/a
1978	2.94	n/a	n/a	n/a
1979	2.94	n/a	n/a	n/a
1980	2.94	n/a	n/a	n/a
1981	2.94	n/a	0.41	n/a
1982	2.94	n/a	0.41	n/a
1983	2.94	n/a	0.41	n/a
1984	2.94	n/a	0.41	n/a
1985	2.94	22.87	0.41	n/a
1986	2.94	22.87	0.41	n/a
1987	2.94	22.87	0.41	n/a
1988	2.94	22.87	0.41	n/a
1989	2.94	22.87	0.41	n/a
1990	2.94	22.87	0.41	n/a
1991	2.94	22.87	0.41	n/a
1992	2.94	22.87	0.41	100.3
1993	2.94	22.87	0.41	145.31
1994	2.94	22.87	0.41	143.2
1995	2.94	22.87	0.41	162.62
1996	2.94	22.87	0.41	51.47
1997	0.00	0.00	0.00	69.37
1998	0.00	0.00	0.00	151.27
1999	311.33	55.13	28.67	110.66
2000	12.62	32.06	0.00	118.79
Average	*14.94*	*22.60*	*1.76*	*117.00*

Notes:

1. Up to 1996, spill values are the average over the period collected and stored in the "usefule Outflow" tables attached to the previous year's annual average energy memos. The data can be found in the "Average Energy" file ... 000.67.05/2.00

2. In 1997 and onward, spill values are actuals taken from TURCONHY.WK4

3. In 1998 the amount of spill in Cat Arm was reduced by 10.20MCM as it was caused by energy stored for customers.

4. In 1999 the amount of spilled water was reduced as there was a significant amount of stored energy for customers carried over from 1998. Salmon River was reduced by 73.67MCM, Cat Arm by 119.96MCM and

Appendix K

Survey Forms and Response Summary

Survey of Utility Regulators –

Background –

Newfoundland and Labrador Hydro generates electricity for much of the province of Newfoundland and Labrador on the east coast of Canada. It has about 1600 MW of capacity, of which about 1000 MW is from hydraulic resources. Newfoundland and Labrador Hydro has been ordered by the provincial Board of Commissioners of Public Utilities (Public Utilities Board, or PUB) to commission an independent study into its forecasting methodology, and to address some related concerns raised in a rate hearing in 2001.

As a result of that order, Newfoundland and Labrador Hydro requested Acres to carry out this study. An important task assigned to us is to find out what the practices are in other regulated jurisdictions.

Respondent please note -

Our report will probably be part of a public record. Although results will be aggregated in the report, the Public Utilities Board is a quasi judicial board, and we can't guarantee that they will not request access to the survey forms.

Since it is a public document, however, Newfoundland and Labrador Hydro can provide the results to the other survey participants.

Contact Name

Position

Organization

Telephone Number

Email Address

Questions

1. Does your organization set or approve rates for the sale of electricity by hydroelectric power producers in your jurisdiction? If yes, please briefly describe the extent of your authority, and state your area of jurisdiction.

2. Does your organization require hydroelectric power producers to provide estimates of expected production, for the purpose of setting or approving rates?

3. If yes to #2, does your organization set any requirements on how such estimates should be derived – e.g., methodology, type of record, length of record.

Notes/Additional Comments

Survey of Utilities –

Background –

Newfoundland and Labrador Hydro generates electricity for much of the province of Newfoundland and Labrador on the east coast of Canada. It has about 1600 MW of capacity, of which about 1000 MW is from hydraulic resources. Newfoundland and Labrador Hydro has been ordered by the provincial Board of Commissioners of Public Utilities (Public Utilities Board, or PUB) to commission an independent study into its forecasting methodology, and to address some related concerns raised in a rate hearing in 2001.

As a result of that order, Newfoundland and Labrador Hydro requested Acres to carry out this study. An important task assigned to us is to find out what the practices are in other regulated jurisdictions.

Respondent please note -

Our report will probably be part of a public record. Although results will be aggregated in the report, the Public Utilities Board is a quasi judicial board, and we can't guarantee that they will not request access to the survey forms.

Since it is a public document, however, Newfoundland and Labrador Hydro can provide the results to the other utility participants.

Contact Name

Position

Organization

Telephone Number

Email Address

A – Development of estimates/Hydrologic Record

1. Do you (or does someone else in your organization) develop estimates of expected production from your hydroelectric resources?

2. What estimates do you develop? e.g., mean, median, other statistics

3. What methodology is used to estimate hydraulic production?

4. If estimates are developed from a sequence, is it an historic record or synthetic sequence?

5. What length of record do you use?

6. How did you (or others) select the record length? If longest possible, what is rationale?

7. Was the entire length of record developed from the same set of data or using the same methodology?

8. Do you drop any data or curtail it to a common period?

9. Why or why not?

10. If so, what are your criteria for curtailing a record?

11. Is trend analysis used in the development of expected annual hydraulic energy production estimates? Trends in what? (e.g., precipitation, streamflow, development?)

12. What are you (or your utilities) doing to assess climate change impacts on the hydroelectric industry?

B – Uses of estimates

1. For what purposes do you use the estimates of hydroelectric energy?

2. Do you use them in operations? (e.g. reservoir planning, water management, production costing)

3. Do you use them in long term planning (typically generation expansion planning)

4. Do you use the estimates of hydraulic energy to set rates ?

5. Do you provide the estimates to others outside your organization, e.g., Are you required to provide them to a regulating agency or others?

6. If so, does the regulating agency set any requirements on how they should be derived – e.g. length or type of record.

7. What is your regulating agency or agencies?

Notes/Additional Comments

Utility Survey Responses - Canadian Utilities

Question		Utility 1	Utility 2	Utility 3	Utility 4	Utility 5
A1	**Estimate expected production from hydro?**	Yes, both op'l and long term planning groups	Yes	Yes	Yes	Yes
A2	**Estimates of …?**	Mean for >2 yrs Median for <2yrs Both 86 yrs	Both deterministic and probabilistic forecasts	Monthly expected production	Quartiles, median	-
A3	**Methodology to estimate hydraulic production?**	Near-term- optimization model Long term system sim model	Computer simulation for part of the system, spreadsheet models for others (changing soon)	Inhouse computer simulation models - vary by plant.	Computer simulation	Optimization model using e.g., precip,snowpack, historic data, operating constraints.
A4	**Historic or synthetic?**	Historic	Historic	Historic	Adjusted Historic	Historical
A5	**Length?**	86 years	1973 - present	Shortest 30 years, avg probably 40-50	58 years	1934 to the present
A6	**How selected?**	Longest possible	Longest given available data	From date plant came into service.	Longest based on actual flow records	Longest Possible. Consider this to give more accurate forecast.
A7	**Same data or methodology?**	No - Some gaps filled, extensions	Yes	Yes	Yes	Yes
A8	**Drop or curtail data?**	No - lengthened with each year.	Yes - some data curtailed to provide common period.	Only in unusual cases.	Most recent years not included until adjusted to common level of development	No
A9	**Why or why not?**	Longest most useful in representing variability, even if early data is less reliable.	Model requirements.	Common period necessary for simulation; longer records dropped.	See A8	All data is from actual records.
A10	**Criteria for curtailing?**	Do not curtail	Model requirements.	-	See A8	-
A11	**Trend analysis?**	No, because no evidence of a clear trend	Not in operations planning.	No - maybe informally for short term.	Not in flows, but in development	Software can model trends.
A12	**Climate change?**	Review, research, sensitivity	Not aware of such activity.	Very little.	Nothing at present, probably part of next flow update	Nothing at the present
B1	**Purposes for estimates of hydro energy?**	Production scheduling; generation expansion planning, evaluating export sales opportunities; forecasting revenues and costs.	Operations planning, maintenance scheduling, decision support for elec. trade, revenue forecasting	Internal.	To develop fuel and purchase power budgets, transaction plan. Also system studies.	Forecasting and predict maximum generation
B2	**Planning water mgt, production costing?**	Yes	Yes	No except scheduling outages.	Yes. Day-to-day operations use real time flows.	Operations - to plan downtime.

Utility Survey Responses - Canadian Utilities

Question		Utility 1	Utility 2	Utility 3	Utility 4	Utility 5
B3	**Generation expansion planning?**	Yes	Yes	No	Yes.	Daily energy plan, Monthly rolling energy production, 18 month energy plan, 10 year production plan
B4	**Rate setting?**	Yes	Yes but no hearing for many years	No	Yes	No
B5	**Provided to regulator?**	Yes	Yes to gov't and utilities commission	No	Yes	Provided to market regulator in order to be in market.
B6	**Regulator sets requirements?**	No	Unsure.	no	No	No requirement for rates; various other requirements under market agreement.
B7	**Regulating agency?**	Public Utilities Board	Utilities Commission	Provincial energy board	Rate review panel.	Market operator.

Utility Survey Responses - US Utilities

Question		Utility 6	Utility 7	Utility 8	Utility 9	Utility 10
A1	**Estimate expected production from hydro?**	Yes	Yes	Yes	Yes	Yes
A2	**Estimates of …?**	Percentiles	Mean weekly, monthly, yearly	Mean monthly flow and generation for 18 months. Will soon start making probabilistic forecasts.	Mean	Mean, median and probabilistic water supply scenarios.
A3	**Methodology to estimate hydraulic production?**	In house computer simulation models	Forecast inflows beyond 3 months are the historic mean.Simulation models optimize production.	Hydrologic computer models.	Computer model	Simulated hydraulic regulation studies. Will soon add the capability of producing optimization scenarios.
A4	**Historic or synthetic?**	Adjusted Historic	Historic	Historic	Synthetic	Historic hydraulic sequences and water supply scenarios from others
A5	**Length?**	~70 years	25-92 years	1948-99	60 years	60 year historic water supply record, dating from July 1928 to September 1989.
A6	**How selected?**	Longest possible (but see B6)	Longest possible. All data considered equally reliable.	Length of suitable available data.	Unknown	Near complete records begin in 1928.
A7	**Same data or methodology?**	Yes	No	Yes.	Yes	Unsure
A8	**Drop or curtail data?**	Recent years not added until water use studies are complete.	No	No (except to get data for the number of stations required)	No	Operational planning studies commonly curtail water years.
A9	**Why or why not?**	Record must be updated every few years to represent current water uses	-	-	-	For operations,water years with low probability are often omitted in
A10	**Criteria for curtailing?**	See A9	-	-	-	Forecasts provided by others are used to select water years from the historical record that have an equal probability of occurrence.
A11	**Trend analysis?**	Doesn't think so.	No - did analysis and found no trend	Appears to be no success with time series analysis	Short term adjustment if trend to dry or wet.	Generation projections will sometimes assume a trend to average or median stream flow conditions.
A12	**Climate change?**	Not aware of it.	No action.	No action so far.	Very little at this time.	Specialist staff assess climate changes; participate in workshops and conferences; monitor and assess research. Monitor climate indices.
B1	**Purposes for estimates of hydro energy?**	Preparing plans for submission to regulator- show how resource will meet load growth.	Revenue optimization, trading purposes, budgeting	Financial strategy, bond rating, outage planning, estimate the required non-hydro production.	To balance load and resources.	To plan marketing strategies project revenue, ensure reliability.
B2	**Planing water mgt, production costing?**	All part of plan in B1	Yes	Yes	Yes	Yes
B3	**Generation expansion planning?**	Yes	Yes in past	No	Yes	Yes
B4	**Rate setting?**	Yes	No	No	Yes	Yes
B5	**Provided to regulator?**	Yes	No	Estimates provided to other utilities sharing water	Estimates to other members of a hydro coordination group.	No requirement;utility provides study results to ratepayers and public agencies.

Utility Survey Responses - US Utilities

Question		Utility 6	Utility 7	Utility 8	Utility 9	Utility 10
B6	**Regulator sets requirements?**	Yes - regulator set most recent 20 years	-	-	No	No
B7	**Regulating agency?**	Public Utilities Commission	2 state boards	FERC	FERC	US DOE; FERC

Regulator Survey Responses

Question		Regulator 1	Regulator 2	Regulator 3
1	**Set/Approve Rates?**	Not for generators, only companies involved in interstate transmission.	Yes	No. Province has an organized spot market where the electricity commodity is traded and a market clearing price is determined. The market is run by the Independent Electricity Market Operator. Market participants all receive the clearing price.
2	**Estimates of Production?**	No, based on cost of service.	Yes. Rates are based on a historical "test year"(12 month period, not necessarily a calendar year). The calculations for the test year use actual experience, such as expenses and investments. The utility is authorized to have a certain return, and to incur prudent expenses. Information for new projects, with no history, can be included with a pro forma adjustment. The estimate for water conditions is for a "normalized" test year.	No
3	**Rquirements on how estimates arrived at?**	-	Yes. Recent hearings have determined a 20 year period for setting the base rate. Formerly used the entire record.	-

Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets

Newfoundland and Labrador Hydro

System Planning Department

April 2003

EXECUTIVE SUMMARY

Following the Newfoundland & Labrador Hydro (Hydro) 2001 General Rate Application (GRA), the Public Utilities Board (the Board) in Order No. P.U. 7 (2002-2003) ordered Hydro:

> **to file with the Board, as part of its next general rate application, a detailed study as outlined in the decision of the Board, as to the proper COS assignment of the GNP assets, the Doyle-Port aux Basques assets and the Burin Peninsula assets.**

This report describes the analysis undertaken by Hydro to respond to the Board order. In keeping with the Board's recommendations related to the treatment of costs in the Cost of Service (COS), the evidence presented in this report clearly demonstrates that all of Hydro's generation assets on the Island Interconnected System, including the Great Northern Peninsula (GNP) generation assets, provide significant benefit to all customers on the Island Interconnected system and should be assigned as common plant.

Further, the evidence presented in this report supports a revised set of guidelines related to the appropriate assignment of transmission assets. This evidence clearly demonstrates that the presence of a generation asset at the end of a radial transmission line serving a single customer does not necessarily dictate the assignment of the transmission assets in the same manner as that of the generation (i.e. as common). The application of the revised guideline remains dependent on one's interpretation of substantial benefit. Hydro has presented rationale for an appropriate interpretation of the guideline with recommendations regarding the assignment of transmission assets.

In this review of the GNP, Doyles-Port aux Basques and Burin Peninsula assets, Hydro's recommendations with respect to the application of the proposed assignment guidelines would result in the following:

- Generation assets on the GNP – Assigned to common plant. This is a change from the 2003 GRA assignment in which the assets are specifically assigned to Hydro Rural.
- Hydro owned generation assets on the Burin Peninsula – Assigned as common plant. No change from the 2003 GRA assignment.
- GNP transmission assets – Specifically assigned to Hydro Rural. No change from the 2003 GRA assignment.
- Doyles-Port aux Basques transmission assets – Specifically assigned to Newfoundland Power. No change from the 2003 GRA assignment.
- Burin Peninsula transmission assets – Assigned to common plant. No change from the 2003 GRA assignment.

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1 INTRODUCTION

Following the Newfoundland & Labrador Hydro (Hydro) 2001 General Rate Application (GRA), the Public Utilities Board (the Board) issued the following as decision No. 58 of Order No. P.U. 7 (2002-2003):

> *Based on the evidence before it at this hearing the Board is not prepared to confirm the change in assignment from NLH rural to common of the generation and transmission assets on the GNP. The proposed change in the assignment of the Doyles-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will reconsider this issue at NLH's next rate hearing. The Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including an assessment of the impacts on system reliability and the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected system. This study should also review the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the grid.*

This report describes the analyses undertaken, to address the Board's decision.

2 BACKGROUND

In Order No. P.U.7 (2002-2003), June 7, 2002, the Board on page 110 made reference to the 1993 Generic Cost of Service (COS) Report having a number of recommendations related to the treatment for the Great Northern Peninsula (GNP) interconnection which were outlined in the Board's 1995 Rural Electrical Service Report on page 39:

"Assignment of Costs

- *The cost of transmission dedicated to serve one customer should be specifically assigned*[13]*, and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers.*
- *Transmission lines dedicated to the service of Newfoundland & Labrador Hydro rural rate classes be included in a sub-transmission function, which means that the costs attributed thereto should be allocated exclusively to such classes."*

The Board examined the issues of cost assignment and cost classification surrounding the treatment of the GNP interconnection costs in its 1995 Report and stated:

"The Board is not convinced sufficient evidence has been provided to conclude whether or not the assignment of generation assets and transmission lines should be common. Newfoundland and Labrador Hydro has warned that if the assignment rules are applied differently, the results may not be consistent with the treatment afforded in similar circumstances elsewhere in the interconnected rural system. However, the Board is struck by the inconsistency in the proposed treatment whereby Newfoundland and Labrador Hydro

[13] *Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes of customers are referred to as common costs.*

treats generation assets as common but the related transmission line is treated as specifically assigned."

On this basis the Board made an interim cost treatment decision until further information could be presented at a future hearing as stated below:

"The Board concludes that the treatment of the Great Northern Peninsula interconnection by Newfoundland and Labrador Hydro in its cost of service study requires modification. Until such time as a more detailed study of proper cost assignment for the rural interconnected system can be concluded, the following recommendations are proposed: both the 138 kV transmission line and generation assets should be treated as common in the assignment of costs; and transmission assets, related to transmission lines of lesser voltage, should continue to be treated as specifically assigned, through a sub-transmission function. This treatment is of an interim nature until the Board re-examines the cost assignment rules at a future hearing."

In its 2001 GRA, in an effort to assign assets objectively and consistently across the Island system, Hydro modified the assignment guideline related to transmission assets connecting a single customer and remote generation to the grid in accordance with the interim recommendation of the Board. The guideline was stated in the pre-filed testimony of H. G. Budgell, page 17 as follows:

d) All of Hydro's transmission and terminal station plant that connects a single customer and remote generation or voltage support equipment, that is of substantial benefit to all customers on the grid. For the purposes of this guideline if, under any normal operating scenario the output of remote generation can be delivered to the 230 kV grid (i.e. in excess of radial load), then the remote generation is considered to be of *substantial benefit to all customers and as such the transmission and terminals plant connecting it to the grid would be assigned common.*

To illustrate this guideline Hydro put forward a test that, if under light load conditions the combined generation on the radial line exceeds the radial load, the assets would be assigned common.

However, the Board again concluded that it did not have sufficient evidence to accept Hydro's proposed change in assignment of GNP assets to common and directed Hydro to study the value of the interconnection of the GNP assets to the Island Interconnected system. This review was also to study the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the interconnected system. A detailed listing of these assets is shown in Table 2-1 and illustrated in Figure 2-1.

Cost assignment for these assets in Hydro's 2003 GRA, based on the previous decision of the Board and prior to further review, are as follows

- GNP generation and transmission assets – Specifically assigned to Hydro Rural.
- Doyles-Port aux Basques transmission assets – Specifically assigned to Newfoundland Power.
- Burin Peninsula transmission assets – Assigned to common plant.

The remainder of this review presents analysis related to the value of these assets to the interconnected system and the development of a set of guidelines for the assignment of generation and transmission assets connected to the Island Interconnected system.

Table 2-1

Generation Assets			
	Net Capacity (MW)	Energy (GWh)	
		Firm	Average
GNP Interconnection			
Newfoundland & Labrador Hydro			
Hawke's Bay (diesel)	5.0	--	--
Roddickton (diesel)	1.7	--	--
Roddickton (hydro)	0.4	0.7	1.0
St. Anthony (diesel)	8.0	--	--
TOTAL	15.1	0.7	1.0
Doyles-Port aux Basques			
Newfoundland Power			
Port aux Basques (diesel)	2.5	--	--
Port aux Basques (gas turbine)	7.2	--	--
Rose Blanche (hydro)	6.1	17.5	23.0
TOTAL	15.8	17.5	23.0
Burin Peninsula			
Newfoundland Power			
Greenhill (gas turbine)	25.0	--	--
West Brook, Lawn, & Fall Pond (hydro)	1.7	5.9	7.7
Newfoundland & Labrador Hydro			
Paradise River (hydro)	8.0	27.0	39.0
TOTAL	34.7	32.9	46.7

Newfoundland & Labrador Hydro Transmission Assets			
	Voltage (kV)	Terminal Stations (from/to)	
GNP Interconnection			
TL239, TL 259	138	Deer Lake	Peter's Barren
TL221	66	Peter's Barren	Hawke's Bay
TL241, TL244, TL256	138	Peter's Barren	St. Anthony Airport
TL261	69	St. Anthony Airport	St. Anthony
TL257	69	St. Anthony Airport	Roddickton
Doyles-Port aux Basques			
TL214	138	Bottom Brook	Doyles
TL215	66	Doyles	Grand Bay
Burin Peninsula			
TL212	138	Sunnyside	Linton Lake
TL219	138	Sunnyside	Salt Pond

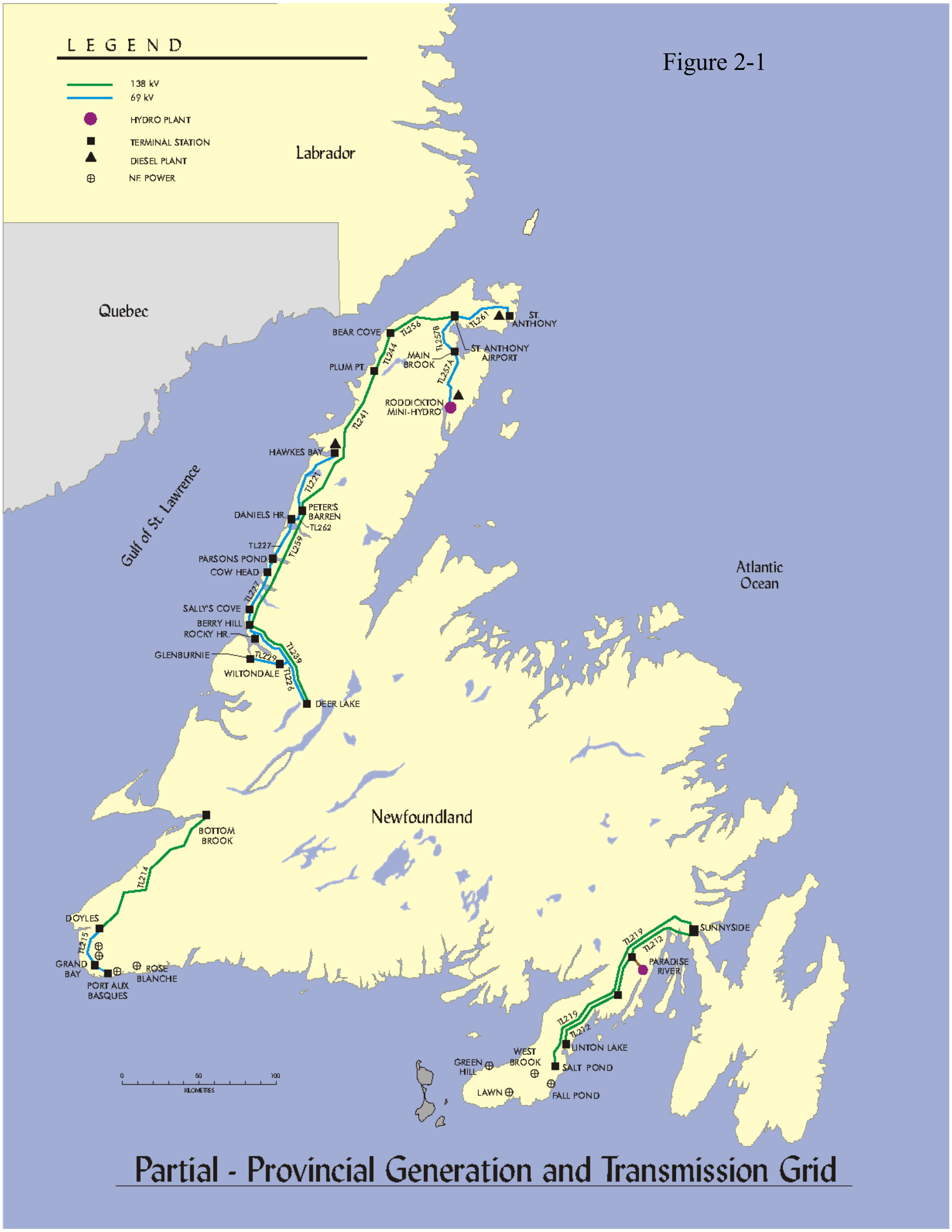

Figure 2-1

Partial - Provincial Generation and Transmission Grid

3 ASSIGNMENT OF GENERATION ASSETS

This section presents analysis and discussion to develop a recommendation as to the appropriate assignment of the GNP, Doyles-Port aux Basques and Burin Peninsula generation assets in the COS. First, a reliability assessment analysis is performed to identify the value of these assets to all customers on the grid. This is followed with a discussion of how these assets are integrated into the operation of the system.

3.1 Reliability Assessment

One method to illustrate the value of the generation assets to the overall system is through reliability assessment. To assess the impact on reliability of the Island Interconnected system of the GNP, Doyles-Port aux Basques and Burin Peninsula generation assets, it is necessary to compare system reliability indices with these assets included in the mix of generation, against reliability indices with these assets removed from the generation mix. As these indices are used to determine the timing of requirements for new generation, it provides an objective indication of the value of these assets to the overall system.

The following summarizes the key information used to perform this analysis:

3.1.1 Load Forecast

This study uses the 2003 Planning Load Forecast as developed by Hydro's System Planning Department. This forecast is for the total Island Interconnected system and includes demand and energy met by our customer's resources. It assumes Voisey's Bay investments in Labrador as well as commercial refining operations on the Island starting in 2012.

3.1.2 Existing plus Committed System

Table 3-1 provides a summary of the existing plus committed capacity and energy capability of the Island System through the end of 2003. Hydro is the prime supplier of electrical energy, accounting for 80% of the Island's net capacity. The remaining capacity is supplied by Newfoundland Power Inc. Limited (8%), Corner Brook Pulp and Paper Limited (6%) and Abitibi Consolidated Inc. (3%). As well, Hydro has contracts with four Non-Utility Generators (NUGs) (3%) for the supply of energy.

Hydroelectric generating units account for 65% of the total existing Island net capacity and firm energy capability. The remaining net capacity comes from thermal resources and is made up of conventional steam, combustion turbine and diesel generating plants. Approximately 70% of the existing thermal capacity is located at the Holyrood Thermal Plant and is fired by heavy oil. The remaining capacity is located at sites throughout the Island.

Table 3-1

Island System Capability	Net Capacity (MW)	Energy (GWh)	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2234	2596
Upper Salmon	84.0	476	550
Hinds Lake	75.0	283	340
Cat Arm	127.0	605	704
Paradise River	8.0	27	37
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
TOTAL HYDRO	887.3	3630	4234
Holyrood	465.5	2996	2996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
TOTAL THERMAL	598.2	2996	2996
Newfoundland Power Inc.			
Hydro	93.2	323	424
Combustion Turbine	47.2	-	-
Diesel	7.0	-	-
TOTAL	147.4	323	424
Corner Brook Pulp and Paper Ltd.			
Hydro	121.4	781	860
Abitibi Consolidated Inc.			
Hydro	58.5	443	470
Non-Utility Generators			
Hydro	19.0	107	157
TOTAL EXISTING (Dec. 2002)	**1831.8**	**8280**	**9141**
Committed Additions (2003)			
Granite Canal	40.0	216	224
ACI Beeton + Bishop's Falls Upgrade	32.3	110	137
CBP&P Co-generation	15.0	100	100
TOTAL EXISTING + COMMITTED	**1919.1**	**8706**	**9602**

3.1.3 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the Island Interconnected System which sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to insure an adequate supply for firm load:

Energy

The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

Capacity

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year.

Based on an examination of the load forecast with the planning criteria, energy and capacity deficits are forecast to occur starting in 2009 and 2011 respectively. Table 3-2 presents a summary of these near term capacity and energy requirements.

Table 3-2

Near Term Capability Requirements						
	Load Forecast		Existing plus Committed System			
Year	Peak MW	Firm Energy GWh	Installed Net Capacity MW	Firm Capability GWh	LOLH hrs/yr	Energy Balance (GWh)
2003	1,578	8,441	1,919	8,706	0.6	265
2004	1,602	8,504	1,919	8,706	1.1	202
2005	1,607	8,512	1,919	8,706	1.2	194
2006	1,613	8,556	1,919	8,706	1.3	150
2007	1,624	8,606	1,919	8,706	1.6	100
2008	1,634	8,653	1,919	8,706	1.9	53
2009	1,643	8,716	1,919	8,706	2.3	***(10)***
2010	1,654	8,793	1,919	8,706	2.8	(87)
2011	1,666	8,865	1,919	8,706	3.5	(159)
2012	1,728	9,309	1,919	8,706	10.4	(603)

The value of the GNP, Doyles-Port aux Basques and Burin Peninsula generation assets can be determined through a comparison of near term requirements with and without these assets in the generation mix. Table 3-3 presents the result of this comparison for each group of assets under review, and for the assets as a whole.

Table 3-3

	Existing plus Committed System						
	Base Case		Less GNP	Less Doyles-Port aux Basques	Less Burin Peninsula	Less GNP, Doyles-Port aux Basques and Burin Peninsula	
Year	LOLH hrs/yr	Energy Balance GWh	LOLH hrs/yr	LOLH hrs/yr	LOLH hrs/yr	LOLH hrs/yr	Energy Balance GWh
2003	0.6	265	0.8	0.9	1.2	2.2	214
2004	1.1	202	1.4	1.5	2.0	3.5	151
2005	1.2	194	1.6	1.6	2.2	3.8	143
2006	1.3	150	1.8	1.8	2.5	4.2	99
2007	1.6	100	2.1	2.2	2.9	5.0	49
2008	1.9	53	2.5	2.5	3.3	5.6	2
2009	2.3	*(10)*	3.0	3.0	4.1	6.8	*(61)*
2010	2.8	(88)	3.7	3.7	5.0	8.3	(138)
2011	3.5	(159)	4.6	4.6	6.1	10.0	(210)
2012	10.4	(603)	13.2	13.1	16.9	26.0	(654)

The removal of each of the GNP, Doyles-Port aux Basques and Burin Peninsula generation assets advances the timing of capacity deficits, and thus the requirement for capacity additions, by two to four years. The effect of the combined removal of all of these assets advances the timing of capacity deficits from 2011 to 2004. Since the only firm energy capability (GWh) resulting from these units is associated with the small hydro plants, the timing of the energy deficit in all cases is unchanged at 2009. Therefore, from a generation planning point of view, the value of these assets is in their contribution to the overall reliability of the generation system with the resultant impact on resource decisions of the past, and as illustrated in

Table 3-3, resource decisions yet to be made. This contribution is to the benefit of all customers on the Island Interconnected system.

Note that the application of the generation planning criteria does not consider the location on the system of individual generation assets. The only consideration at this stage of the planning process is that the generation assets must be capable of delivering capacity and energy to the system and that the system be capable of utilizing that capacity when needed. On a go-forward basis, when Hydro is seeking new generation capacity for the system, the same capacity value would be assigned to a particular asset were it located in St. Anthony or in St. John’s as long as there were no locational limitations (such as transmission constraints) affecting the ability of the system to utilize that new capacity.

3.1.4 Estimated Value of Generation Assets

It is impossible to place an accurate dollar value estimate on the value that these generation assets have brought to the Island Interconnected System since their connection. To do so would require a historical analysis in which one would compare the economic implications of resource decisions of the past with those that would have been made had the generation assets not been in existence. While the theory behind the analysis appears relatively simple and straightforward, it would be impossible to identify and incorporate all considerations having impacted those historical resource decisions to an alternate history in which certain resources were not available.

However, it is possible to get an indication of the value that these assets bring to the Island Interconnected System through an examination of the costs that would be incurred if Hydro were required to purchase a similar amount of peaking capacity today. Based on cost estimates for a new simple-cycle combustion turbine, the levelized annual cost for new peaking capacity coming on-line in 2004 is on the order of $100/kW/year. This yields an annual valuation of approximately $6.5 million per year for the total of 64.5 MW of generation assets on the GNP, Doyles-Port aux Basques and Burin Peninsula radial systems. As indicated in Table 3-3, the removal of these assets from existing system capability would advance the timing of peaking capacity requirements by 7 years from 2011 to 2004. This implies a simple valuation of the generation assets of some $45.5 million due to the avoidance of capacity additions in that timeframe. It follows that the presence of these assets on the system has had similar impacts on past decisions.

3.2 System Operation

The existing system requires approximately 16%, or 300 MW, of reserve capacity to meet the established planning criteria. Peaking plant, such as combustion turbine and diesel units contribute to this reserve capacity and serve as a backup to base system generation. The units are located in diverse locations throughout the system to meet this need and also to serve as a source of regional emergency supply. As reserve capacity, and following a merit order dispatch procedure which seeks to minimize operating costs, it is only in the event of unforeseen load growth, or base generation outages that these higher cost sources would be expected to operate.

Reserve capacity is put into service and loaded up in response to total system requirements. In doing so it effectively off-loads generation at other locations. This provides the ability of generation elsewhere on the system to respond to system requirements (i.e. system voltage, frequency regulation, etc.) to maintain the integrity of the entire system.

The System Operating Instruction "Generation Loading Sequence and Generation Shortages" (see Appendix A) establishes the guidelines to be followed in the event of a generation shortage on the Island Interconnected system. The intent of this guideline is to minimize the number and duration of outages to customers on the system. All of the generation assets located on the GNP, Doyles-Port aux Basques and Burin Peninsula systems are included in the "Normal Generation Loading Sequence" as outlined in the operating instruction. If, after all generation is brought on-line and all interruptible load has been canceled, it is apparent that a generation shortage may occur, the final step in the operating instruction is to implement customer load shedding.

The conclusion that is implied by this operating instruction is that, under a generating capacity shortage, and in the absence of the GNP, Doyles-Port aux Basques and Burin Peninsula generation assets, customer load shedding would occur sooner than would otherwise occur and in greater quantities. Since these load control activities affect all customers on the interconnected system, the value of the generation assets are to the benefit of all customers on the system.

At Hydro's 2001 GRA, the Industrial Customers presented argument to the effect that, since the GNP generation assets have seldom been operated to meet a generation capacity shortage since their interconnection in 1996, therefore they do not provide substantial benefit to customers outside of the GNP. Since 1996, Hydro has seen relatively good performance from its generation assets. In addition, the Island system has gone through a period of relatively high reserve margins due to warmer than normal winters and the general economic slowdown in rural Newfoundland. These factors combined have resulted in the ability to meet the demand of the system using lower cost base load generation sources and avoiding the need to utilize peaking resources.

Since the 2001 GRA, the value of reserve capacity was demonstrated on at least two occasions. On January 30, 2003, the diesel units at Hawke's Bay and at St. Anthony were operated in support of the Island Interconnected system. Following the failure of lightning arresters at Oxen Pond Terminal Station in St. John's, and the subsequent trip of all three units at Holyrood, the GNP generation was brought on-line to aid in system restoration. Also, a year earlier, on January 31, 2002 the load on the interconnected system was at an all-time peak, all three units at Holyrood were operating near full capacity, and hydraulic production on the system was near peak capacity. The loss of either of the units at Holyrood or of the larger hydraulic units would have required the use of all available peaking capacity, including diesel, to meet load. In preparation for such an event, the diesel units at Hawke's Bay and St. Anthony were tested to insure availability if required. Fortunately, on that day all of the larger generation assets on the island operated without incident, and the diesels were not required.

3.3 Generation Allocation Guideline

Based on the preceding analysis, it is Hydro's position that all of its' generation assets, regardless of location, are of significant benefit to all customers on the interconnected system and should be assigned as Common Plant. Therefore, Hydro advocates maintaining the guideline for the assignment of Hydro's generation assets to common as proposed during the 2001 GRA and all previous referrals to the Board:

The following facilities will be assigned as Common Plant:

- *All of Hydro's production facilities (hydraulic, thermal, gas turbine and diesel)*

The application of this guideline will result in a change in assignment of the GNP generation assets from the current treatment as Specifically Assigned (to Hydro Rural) to Common Plant. The impact of this change in generation assignment from that filed in Hydro's 2003 GRA as determined through a COS analysis is presented in Appendix B.

4 ASSIGNMENT OF TRANSMISSION ASSETS

In Order No. P.U.7 (2002-2003) the Board on page 110 made reference to the 1993 Generic Cost of Service (COS) Report having a number of recommendations related to the treatment for the Great Northern Peninsula (GNP) interconnection which were outlined in the Board's 1995 Rural Electrical Service Report on page 39:

"Assignment of Costs

The cost of transmission dedicated to serve one customer should be specifically assigned[13]*, and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers."*

In an effort to apply the Board's recommendation objectively and consistently across the Island Interconnected system, in preparation of its 2001 GRA, Hydro revised its guidelines to further clarify the interpretation of "substantial benefit". The guideline that is of importance to this review of the GNP (et. al.) assets is the following for the assignment to Common Plant (pre-filed testimony of H. G. Budgell, page 17):

d) All of Hydro's transmission and terminal station plant that connects a single customer and remote generation or voltage support equipment, that is of substantial benefit to all customers on the grid. For the purposes of this guideline if, under any normal operating scenario the output of remote generation can be delivered to the 230 kV grid (i.e. in excess of radial load), then the remote generation is considered to be of

[13] *Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes of customers are referred to as common costs.*

substantial benefit to all customers and as such the transmission and terminals plant connecting it to the grid would be assigned common.

To illustrate this guideline Hydro put forward a test that, if under light load conditions the combined generation on the radial line exceeds the radial load, the assets would be assigned common. However, during the course of the hearing it became clear that the efficacy of the proposed test was in question as it inadvertently directed undue attention to the time of the year when reserve generation would have limited use.

4.1 Transmission Allocation Guideline

Unlike the previous analysis that clearly demonstrates the benefit of Hydro's generation assets to all customers on the system, for transmission assets it is difficult to establish a quantitative test to identify what is meant by "significant benefit". This difficulty stems from the nature of cost assignment which is an exercise in judgment. Therefore, with respect to the allocation of transmission assets connecting a single customer and generation to the interconnected system, Hydro proposes the following guideline for the assignment of transmission and terminal station plant to common:

The following facilities will be assigned as Common Plant:

- *All of Hydro's transmission and terminal station plant that connects a single customer and generation or voltage support equipment, that is of substantial benefit to more than one customer.*

In the interpretation of this guideline, Hydro proposes that factors such as historical assignment, primary function, and quantity of generation be weighed in determining the ultimate assignment of the transmission and terminal station assets.

4.2 Allocation Consistency

In its 1995 Report the Board stated:

"…the Board is struck by the inconsistency in the proposed treatment whereby Newfoundland and Labrador Hydro treats generation assets as common but the related transmission line is treated as specifically assigned."

As is demonstrated in this report, the generation assets on the GNP, Doyles-Port aux Basques and Burin Peninsula radial lines are clearly of substantial benefit to all customers on the Island Interconnected system from both a generation planning and system operation point of view. Further, the physical location of the generation on the system is of little consequence. Having established this condition, it is necessary to consider if an inconsistency would be created if the connecting transmission and terminals assets were assigned differently.

There are two key factors to consider in determining if generation and the connecting transmission and terminal station assets could logically be assigned differently:

Planning Basis - The application of the generation planning criteria as outlined previously does not consider the location of individual generation assets on the system. The only consideration at this stage of the planning process is that the generation assets must be capable of delivering capacity and energy to the system and that the system be capable of utilizing that capacity when needed. The process of planning the transmission system focuses on the ability to maintain acceptable voltages, reliability and stability throughout the system. Transmission facilities must be adequate to connect generation to the grid and to serve the requirements of customers connected to the grid. Generation is not assigned to specific customers and the manner in which it is dispatched is dependent only on cost and system loading considerations.

COS Treatment of Similar Assets – Providing Newfoundland Power with a demand credit, particularly for their thermal generation, acknowledges the benefit that these assets bring to the interconnected system, i.e. they are of common benefit to all customers. Many of these generation assets are located well within Newfoundland Power's service territory with the connecting transmission (and distribution) lines owned and paid for by Newfoundland Power's customers. Therefore, this treatment of Newfoundland Power thermal generation assets in the COS, which has been in place since the 1970's, would support the position that transmission assets need not necessarily be allocated in the same manner as the remote generation assets they connect to the interconnected system.

The conclusion drawn is that remote generation and the connecting transmission and terminal station assets could logically be assigned differently in the COS. Further, in their Final Submission to the Board in the 2001 GRA (page 32), the Industrial Customers agree that an inconsistency would not exist were the GNP generation and transmission assets assigned differently.

4.3 Proposed Transmission Assignment

The following sets out the results of Hydro's interpretation of the proposed transmission assignment guideline to the GNP, Doyles-Port aux Basques and Burin Peninsula transmission assets:

GNP Transmission Assets: The GNP assets clearly fall under the assignment guideline associated with the connection of a single customer (Hydro Rural) and remote generation or voltage support equipment to the Island grid. Prior to the 1996, transmission and terminals assets on the GNP (up to and including the Bear Cove Terminal Station) were specifically assigned to Hydro Rural. An examination of the rationale for the 1996 expansion of the transmission system to interconnect the previously isolated St. Anthony/Roddickton system clearly indicates that the transmission system was constructed for the benefit of customers on these isolated systems. The generation assets on the GNP, which were originally constructed to serve the isolated system, as a result of the interconnection now serve as reserve capacity to the interconnected system. While of benefit to all customers, these generation assets are not of sufficient magnitude, in Hydro's opinion, to justify assignment of the GNP transmission assets to common given the dominant use of the transmission system in serving that customer group. Therefore, while cost assignment is a matter of judgment with many issues and no absolute answer, on balance Hydro's interpretation of the guidelines would result in a recommendation that the GNP transmission assets be specifically assigned to Hydro Rural.

Doyles-Port aux Basques: Similar to the GNP, the transmission assets of the Doyles-Port aux Basques system fall under the assignment guideline associated with the connection of a single customer (Newfoundland Power) and remote generation or voltage support equipment to the Island grid. As well, like the GNP transmission assets, the primary purpose of the Doyles-Port aux Basques transmission assets is to provide service to Newfoundland Power customers on that radial system. This position is further supported in previous Board decisions in which these transmission assets were specifically assigned to Newfoundland Power. The generation assets also located on that radial, while of benefit to all customers, are not of sufficient magnitude, in Hydro's opinion, to justify assignment of the transmission assets to common given the dominant use of the transmission system in serving that customer group. Therefore, on balance, Hydro's interpretation of the guidelines would result in a recommendation that the Doyles-Port aux Basques transmission assets be specifically assigned to Newfoundland Power.

Burin Peninsula: The Burin Peninsula transmission assets serve both Newfoundland Power and Hydro Rural customers and it connects generation assets of Newfoundland Power (25.6 MW) and of Hydro (8 MW) to the Island grid. Therefore, the Burin Peninsula transmission assets fall under the guideline associated with the connection of two or more customers to the grid. Prior to the construction of the Paradise River hydroelectric facility in 1989, and the connection of Hydro Rural customers to this transmission system (Monkstown in 1988, Petite Forte in 1993 and South East Bight in 1998), the Burin Peninsula transmission assets were assigned to common plant on the basis of interconnecting significant generation located on the system. While Newfoundland Power is now relocating a portion of the thermal generation (15 MW gas turbine) elsewhere on the system, considering the connection of the Paradise River hydroelectric facility and of Hydro Rural customers to the Burin Peninsula transmission system, Hydro's interpretation of the guidelines would result in a recommendation that the Burin Peninsula transmission assets remain assigned to common plant.

The application of these recommendations will not change the assignment of transmission assets from that filed in Hydro's 2003 GRA:

- GNP transmission assets – Specifically assigned to Hydro Rural.
- Doyles-Port aux Basques transmission assets – Specifically assigned to Newfoundland Power.
- Burin Peninsula transmission assets – Assigned to common plant.

5 CONCLUSIONS

Based on this review of the value of the Great Northern Peninsula generation and transmission assets, and of the value of the Doyles-Port aux Basques and Burin Peninsula transmission assets to the Island Interconnected System, Hydro proposes a revision to the guidelines for the assignment of plant. These revisions reflect the requirement that each component of plant be assigned to customers in a fair and equitable manner. For the purpose of plant assignment, customer includes Newfoundland Power, individual Industrial Customers and Hydro Rural. Plant is assigned as either “common” or “specifically assigned”.

Common Plant is defined as plant that is of substantial benefit to more than one firm customer. Costs for common plant are assigned to all customers of the system.

The following facilities have been assigned as Common Plant:

a) All of Hydro’s production facilities (hydraulic, thermal, gas turbine and diesel);

b) All of Hydro’s transmission and terminal station plant, 66 kV and above, that is of substantial benefit to more than one customer;

c) All of Hydro’s transmission and terminal station plant whose sole purpose is the interconnection of a generating facility with the system. Transmission and terminal station plant in this category have their costs classified on the same basis as the generation that it interconnects; and

d) All of Hydro’s transmission and terminal station plant that connects a single customer and generation or voltage support equipment, that is of substantial benefit to more than one customer.

Specifically Assigned Plant is defined as plant that is of benefit to only one customer. Costs for specifically assigned plant are assigned directly to the benefiting customer.

All of Hydro's generation and distribution facilities in the Isolated Rural Systems and distribution facilities in the interconnected systems have been assigned to Hydro Rural.

Hydro Rural Sub-transmission is defined as all transmission and terminal station plant serving only Hydro Rural rate classes.

NP-IC Sub-transmission is defined as transmission and terminal station plant, which serves both Newfoundland Power and an Industrial Customer but not Hydro Rural and has an original cost of at least 2% of the total transmission and terminal stations costs.

In this review of the GNP, Doyles-Port aux Basques and Burin Peninsula assets, the application of Hydro's recommendations with respect to the above guidelines would result in the following:

- Generation assets on the GNP – Assigned to common plant. This is a change from the 2003 GRA assignment in which the assets are specifically assigned to Hydro Rural.
- Hydro owned generation assets on the Burin Peninsula – Assigned as common plant. No change from the 2003 GRA assignment.
- GNP transmission assets – Specifically assigned to Hydro Rural. No change from the 2003 GRA assignment.
- Doyles-Port aux Basques transmission assets – Specifically assigned to Newfoundland Power. No change from the 2003 GRA assignment.
- Burin Peninsula transmission assets – Assigned to common plant. No change from the 2003 GRA assignment.

The impact of this change in generation assignment from that filed in Hydro's 2003 GRA as determined through a COS analysis is presented in Appendix B.

Appendix A

System Operating Instruction:

Generation Loading Sequence and Generation Shortages

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES	**Rev. No.**	3
		Page 1	**of** 2

INTRODUCTION

In the event of a system generation shortage, the following guidelines shall be followed in the sequence outlined in order to minimize outages to customers:

PROCEDURE

A. Normal Generation Loading Sequence

1. Bring on line all available Hydro hydraulic and steam generators and load them to near full capacity.

2. Request Newfoundland Power to maximize their hydro production.

3. Request Deer Lake Power and Non-Utility Generators to maximize their hydro production.

4. Notify customers taking non-firm power and energy that if they continue to take non-firm power the energy will be charged at higher standby generation rates. Ask Newfoundland Power to curtail any interruptible loads available.

5. Start and load standby generators, both Hydro and Newfoundland Power units, in order of increasing average energy production cost with due consideration for unit start-up time.

6. Cancel all non-firm power delivery to customers and ensure all industrial customers are within contract limits.

PREPARED BY:	APPROVED/CHECKED BY:	ISSUED DATE:	1992-07-16
R. Butler		REV. DATE:	2003-03-31

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES	**Rev. No.**	03
		Page 2	**of** 2

PROCEDURE (cont'd.)

B. Generating Capacity Shortage

If load is still increasing and it is apparent that a generation shortage may occur, proceed as follows:

7. Ensure that steps (A1) through (A6) have been followed and implemented.

8. Inform Newfoundland Power of the need to reduce voltage at Hardwoods and Oxen Pond to minimum levels to facilitate load reduction. Begin voltage reduction.

9. Request industrial customers to shed non-essential loads and inform them of system conditions.

10. Request industrial customers to shed additional load.

11. Request Newfoundland Power to shed load by rotating feeders. At the same time, shed load by rotating feeders in Hydro's Rural areas where feeder control exists.

PREPARED BY: R. Butler	**APPROVED/CHECKED BY:**	**ISSUED DATE:**	1992-07-16
		REV. DATE:	2003-03-31

Appendix B

Cost of Service Analysis:

Impact of Changes in Assignment

Newfoundland and Labrador Hydro
2004 Test Year Scenario Analysis
Customer Imapcts: GNP Generation Treated as Common

		1	2	3	4	5	6
		Revenue Requirement Before Revenue Credit and Deficit Allocation			Revenue Requirement After Revenue Credit and Deficit Allocation		
		GNP Generation Assigned Rural	GNP Generation Assigned Common	Increase (Decrease)	GNP Generation Assigned Rural	GNP Generation Assigned Common	Increase (Decrease)
	Total System						
1	Newfoundland Power	222,506,054	223,708,170	1,202,115	258,876,731	258,888,561	11,830
2	Island Industrial	52,290,690	52,481,844	191,154	52,313,650	52,504,786	191,136
3	Labrador Industrial	2,654,841	2,654,841	-	2,654,841	2,654,841	-
4	CFB - Goose Bay Secondary	129,975	129,975	-	3,014,118	3,014,118	-
5	Rural Labrador Interconnected	10,694,710	10,694,710	-	12,706,161	12,548,181	(157,980)
	Rural Deficit Areas						
6	Island Interconnected	54,593,258	53,244,975	(1,348,283)	35,167,578	35,167,578	-
7	Island Isolated	8,299,138	8,299,138	-	1,575,076	1,575,076	-
8	Labrador Isolated	20,101,385	20,101,385	-	6,192,661	6,192,661	-
9	L'Anse au Loup	2,745,185	2,745,185	-	1,514,420	1,514,420	-
10	**Subtotal**	**85,738,966**	**84,390,683**	**(1,348,283)**	**44,449,735**	**44,449,735**	**-**
11	**Total**	**374,015,236**	**374,060,222**	**44,986**	**374,015,236**	**374,060,222**	**44,986**

A Report of Joint Co-ordination Between

Newfoundland and Labrador Hydro and Newfoundland Power

Newfoundland & Labrador Hydro
December 2002

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Introduction

The legislative mandate set out in the *Public Utilities Act* and the *Electrical Power Control Act, 1994* effectively requires that electrical utilities operating in the Province of Newfoundland and Labrador serve their customers at the lowest cost consistent with safe, reliable service. The regulated electric utilities serving the island of Newfoundland, Newfoundland & Labrador Hydro-Electric Corporation ("Hydro") and Newfoundland Power Inc. ("Newfoundland Power"), have long recognized their obligation to ensure that their respective operations are coordinated in a way that ensures that service is provided to customers at the lowest reasonable cost.

In 1997, Hydro and Newfoundland Power established a joint task force to explore feasible opportunities to reduce costs through the identification and elimination of duplication and through the sharing of resources. While this initiative determined that the areas of overlap were limited, there were several areas identified where potential exists for the sharing of resources to the benefit of customers. Progress was made, most significantly in relation to meter testing and equipment sharing, however, at that time there was no final report completed.

The issue of duplication of resources was reviewed during Hydro's 2001 General Rate Proceeding. In Order No. P.U. 7 (2002-2003), arising out of the proceeding, the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") required that Hydro submit a final report, no later than December 31, 2002, on the results of joint efforts to date to reduce duplication between Hydro and Newfoundland Power. The Board directed that the report should identify and make recommendations concerning additional collaborative opportunities between the two utilities on eliminating duplication and expanding cooperation in the interests of electricity consumers.

This report has been prepared by Hydro, with input from Newfoundland Power, in accordance with the direction of the Board.

1.0 Background

The interconnected electrical system on the island of Newfoundland is comprised principally of the utility plant & equipment of Hydro and Newfoundland Power. Both utilities bear varying degrees of responsibility for the generation, transmission and distribution of electrical energy.

The respective roles of Newfoundland Power and Hydro are, however, fairly distinct. Those areas in which there is overlap, primarily at the lower voltage transmission (i.e., less than 230 kV) and distribution levels, are largely a result of the historical evolution of the electrification of the island.

1.1 Generation & Transmission Operations

The generation of electricity is the most significant cost of providing electrical service on the island of Newfoundland. Hydro and Newfoundland Power maintain a coordinated approach to ensure the most economic deployment of this largest component of the cost of electrical service.

Sources of generation on the island include both hydraulic and thermal facilities, with the bulk of generation facilities being owned and operated by Hydro. Hydro owns and operates 81% of the net island generating capacity and its generating facilities consist principally of large hydroelectric facilities, such as those at Bay d'Espoir and Cat Arm, and the large thermal generating facility at Holyrood. Newfoundland Power plays a minor role in the generation of electricity. Its 23 small hydroelectric generating facilities provide approximately 10 per cent of Newfoundland Power's total electrical energy requirements. The Newfoundland Power generation accounts for approximately 8% of total island capacity with the remaining capacity, approximately 11%, provided by two non-utility generators and Hydro's industrial customers. On average approximately 75 per cent of total generation requirements for the island are provided by hydroelectric energy, with the remainder being provided by thermal energy from the Holyrood facility.

Hydro currently owns and operates 100% of the bulk 230 kV electricity transmission grid on the island. Hydro and Newfoundland Power both own and operate transmission systems at voltages of 138 kV and 66 kV. Hydro owns approximately 65% of the 138 kV and 35% of the 66 kV Island transmission while Newfoundland Power owns 35% of the 138 kV and 65% of the 66 kV.

Responsibility for the dispatch of the various sources of generation to meet system capacity requirements rests with Hydro. Pursuant to this responsibility, Hydro requests that Newfoundland Power make some or all of its generation available when necessary. When not required by Hydro for system capacity purposes, Newfoundland Power operates its small hydroelectric facilities as efficiently as possible to provide low-cost energy to its customers.

The operators at Hydro's Energy Control Centre (ECC) and Newfoundland Power's System Control Centre (SCC) are in daily contact with respect to the coordination of various aspects of system operations. The operation of an isolated electrical system, such as the interconnected system on the Island, presents many technical challenges. To ensure that voltage and frequency levels are maintained within required limits and that interruptions in service to customers are minimized it is essential there be continuous coordination between Hydro and Newfoundland Power.

The operations groups of both utilities also have regular discussions on system operations. In many cases, the completion of capital and operating projects requires that transmission lines be taken out of service. This can impact system operations. To ensure that these circumstances are addressed in a coordinated fashion, Hydro and Newfoundland Power meet regularly to exchange information on planned work and to schedule their respective projects in a way that accommodates both utilities' schedules, improves operational efficiency and minimizes the likelihood of customer outages resulting from unforeseen events.

When widespread outages do occur, there are a number of technical challenges that must be overcome to ensure power is restored as quickly as possible. For example, when a power outage affects a large number of customers, the load must be picked up in stages to ensure the balance is maintained between the size of the load and the capacity of available generation sources. To assist in addressing these challenges, the utilities have cooperated in the development of detailed power restoration plans that provide for a coordinated approach to power restoration in specific circumstances. These plans are facilitated through ongoing communication between the respective utilities' control centres and electronic connections between their respective SCADA systems.

Both utilities have also co-ordinated with regard to high voltage transmission switching. In several areas, notably the Burin Peninsula and the southwest coast, the two utilities have availed of opportunities to share resources where cost savings can be achieved. For example, on the Burin Peninsula, where Hydro has no permanent staff resources in place, Newfoundland Power personnel have on occasion performed switching operations on Hydro's equipment, both at Hydro's request and, when in support of Newfoundland Power operations, with Hydro's permission.

1.2 Distribution Operations

The distribution of electricity is also a significant part of the total cost of providing electrical service on the island of Newfoundland. Both Hydro and Newfoundland Power provide distribution service. Newfoundland Power owns and operates distribution lines providing service to approximately 218,000 customers on the island, while Hydro operates distribution lines providing service to approximately

35,000 customers, 22,000 on the Island and 13,000 in Labrador. In a small number of areas, the electrical distribution services of the two corporations are in close proximity to each other. Generally, however, the areas where the respective utilities provide distribution services are geographically discrete.

There may be potential to achieve cost efficiencies in distribution operations in adjacent territories. Opportunities for further collaboration in distribution operations have been examined as part of the joint review process initiated in 1997. The findings of that process are reviewed in Section 2.0.

1.3 System Planning

The effective and efficient operation of an integrated electrical system requires that the utilities coordinate additions to the system. Since the 1970's Hydro and Newfoundland Power System Planning staff have met regularly to discuss the implications of load forecasts and customer growth on the need for system additions, to determine cost-effective solutions, and to ensure associated technical issues such as system protection and underfrequency load shedding are appropriately addressed. When appropriate the two companies have agreed upon the terms of reference for joint studies required to evaluate optimum transmission/distribution expansion plans for the interconnected system. Over the years there have been several joint studies completed and the mutually agreed to recommendations implemented. Studies have been completed for St. John's Area, Burin Peninsula System and the Western Avalon/ Holyrood 138 kV loop.

Most recently a study was completed that recommended an upgrade plan, involving work by both utilities, for the Little Bay Distribution System in the Springdale area. Problems associated with aged and deteriorated distribution lines necessitated a review early in 2002. One of the feeders originating at Newfoundland Power's Springdale Substation provides the energy supply to Hydro's distribution customers in the nearby Little Bay area. To address reliability concerns, the two utilities conducted a joint analysis, which resulted in the selection of the most cost-effective solution from among four identified options. The chosen option involves the reconstruction and upgrading of the lines of both utilities, and offers a lower cost solution than alternatives that would have been available to the utilities acting independently.

1.4 Other Areas of Coordination

Apart from the System Planning and Operations interaction referred to above there are two other forums for communication between Hydro and Newfoundland Power on matters affecting the Island Interconnected system:

- **Joint Utility Meetings**

The Joint Utility Meetings have been ongoing since the 1970's and are open to operations representatives from Hydro, Newfoundland Power, Corner Brook Pulp & Paper/Deer Lake Power, Abitibi Consolidated Grand Falls, Abitibi Consolidated Stephenville, North Atlantic Refining and the non-utility generators Star Lake and Rattle Brook. These meetings provide a forum for the major system stakeholders to provide an update on their operations and discuss concerns they may have. The Joint Utility Meetings are held annually and member groups take turns hosting the meeting.

- **Inter-utility System Reliability Committee**

The Chief Executive Officers of the two utilities formed the Inter-Utility System Reliability Committee in late 1999. It consists of the Vice-President of Engineering and Operations and Manager of Engineering and Energy Supply from Newfoundland Power and the Vice-President Transmission and Rural Operations and the Manager of System Operations from Hydro.

The Committee meets bi-monthly and discusses reliability issues of common concern. In particular, the reliability indices for the Bulk Electric System for Hydro and the Service Continuity for Newfoundland Power are reviewed. Also the number and impact of underfrequency events are reviewed.

The work of the Committee has resulted in a greater awareness of reliability issues. Both utilities have developed specific targets for improvement for each year that are communicated to all employees.

2.0 1997 Joint Review

In 1997 a joint committee, composed of representatives of management from both utilities and the union bargaining agents, the IBEW, was established to undertake a review of the two utilities' operations. The Committee subsequently confirmed a Terms of Reference and appointed fifteen Working Groups with representation from each utility. The Working Groups were given the mandate to review a particular area of operation and make recommendations for improvements either in, customer service/reliability, enhanced productivity or reduced costs.

The 15 areas reviewed are listed below:

1. Sharing of Specialized Equipment
2. PCB Facilities
3. Customer Enquiries (1-800 number)
4. Printing Services
5. Storage Space
6. Emergency Spill Response
7. Protective Equipment Test Facilities
8. Distribution Maintenance
9. Switching
10. VHF Mobile Radio System
11. Inventories and Common Spares
12. 138 kV Transmission Line Maintenance for Central
13. Equipment and Engineering Standards:
    1. Common Equipment and Engineering Standards
    2. 69 kV and 138 kV Transmission
    3. Substation Design Standards and Practices
    4. Line Maintenance Construction
14. Meter Shop
15. Technical Training

A summary of the findings of each Working Group is set out in this section.

Working Group # 1 - Sharing of Services and Equipment

Hydro and Newfoundland Power have always shared services and equipment. This working group reviewed the sharing of services and specialized equipment available in both utilities to determine if there were further efficiencies to be gained.

Both utilities agreed that sharing of services and specialized equipment results in the least cost, reliable electricity to the consumer and proceeded to formalize the process with a Memorandum of Understanding (MOU) for the Sharing of Services and Equipment.

The MOU on the Sharing of Services and Equipment was established in December 2000. It establishes the conditions and rates for the sharing of services, equipment and materials between the two utilities. Both utilities now have access to a broader base of services and equipment and avail of the process, when appropriate, to expedite power restoration during outages and in emergencies.

Working Group # 2 - PCB Facilities

This Committee reviewed the PCB storage, destruction, and decontamination programs within both utilities with the objective of reducing costs through the coordination of such activities.

Both utilities have an ongoing program of elimination of PCB contaminated equipment, and have been successful, with a diligent program of PCB disposal, in reducing overall inventories of PCB's to the point where, there is only one PCB storage facility for each utility.

The Committee evaluated the feasibility of one common PCB storage facility, and determined that regulatory constraints prevent the amalgamation of storage facilities. However a process was adopted by both utilities in 1997 to ensure that coordination takes place for planned decontamination and destruction of PCB material.

Since 1997 there have been four occasions where Hydro has availed of the Newfoundland Power contractor for PCB disposal.

Working Group # 3 - Customer Enquiries (1-800 Number)

This group undertook an evaluation of the 1-800 number services employed by the two utilities to determine if customer service could be enhanced through the provision of common 1-800 numbers.

This Committee determined that the continued operation of separate 1-800 numbers for billing, credit, technical and other general enquires would provide the best level of customer service.

Both utilities believe that, although there are minimum cost efficiencies available through the combining of the 1-800 emergency numbers for power interruptions and emergencies, there may be customer service improvements if there is a common emergency number throughout the province. In light of the fact that the two utilities now are using the same service provider, which was not the case in 1997, it has been determined this should be reviewed in 2003.

Working Group # 4 - Printing Services

This Committee reviewed the capacity and capabilities of the printing resources available within the two organizations to determine if efficiencies were available in the delivery of print services.

The Committee determined that Newfoundland Power has the capability to undertake some of the Hydro print services and that doing so would result in a cost reduction for Hydro print services. The two utilities have agreed to review this recommendation and, if cost savings exist, a process will be implemented, in 2003, for Newfoundland Power to complete print work for Hydro.

Working Group # 5 - Storage Space

This Committee examined the availability of excess storage space within both utilities throughout the province to determine whether opportunities existed for the practical sharing of space. They determined that there are not a significant number of locations where both utilities operate in close proximity to each other. The only locations where both utilities operate facilities and where sharing of space could be viable are St. John’s, Whitbourne and Stephenville.

A review of the space available at these locations did not identify any excess space beneficial to the other utility.

Working Group # 6 - Emergency Spill Response

This Committee reviewed the emergency spill response procedures employed by both utilities to determine if opportunities existed for cost reduction through the sharing of resources (manpower, materials and equipment). It was determined during this review that the cost reduction potential was not significant. Both utilities depend on private contractors to respond to larger spills, thus ensuring that in-house storage of spill response equipment and materials are kept to a minimum.

The consensus was that an exchange of contact names, keeping each other apprised of planned spill response training and keeping an up to date listing of spill response capability would enhance timely response to spill situations.

The exchange of information between coordinators related to contact personnel and spill response materials was completed during the working group review.

Working Group # 7 - Protective Equipment Test Facilities

This Committee evaluated the present practices and facilities used to test high-voltage protective equipment to ensure worker safety at least cost. The review process included consideration of amalgamation of test facilities, as well as industry best practices for the testing of the equipment.

Two specific opportunities were revealed during the review. Newfoundland Power determined that it could reduce costs by extending the cycle for testing of rubber gloves. In addition, it was determined that Hydro had the capacity to carry out epoxy stick testing for Newfoundland Power in emergency situations. Both of these initiatives have been implemented.

It was determined there would be no advantage in amalgamating the two utilities' test facilities.

Working Group # 8 - Distribution Maintenance

This Committee reviewed rural operations where Hydro and Newfoundland Power operate adjacent to each other to determine the most effective means of operation that would enhance customer service and provide the least cost electricity to the consumer. The Committee explored ways and means of sharing resources that included consideration of the effects of reorganization of maintenance on a geographic basis.

The Committee recommended, and the two utilities agree, that having each other provide emergency service to areas where the other utility has work crews geographically closer to the work will result in improved efficiency. The process for this is established by the MOU on Sharing of Services and Equipment.

Working Group # 9 - Switching

This Committee reviewed the existing arrangements for switching to determine if operating efficiencies would be available through the co-ordination of switching between both utilities. The Committee concluded that there are efficiencies to be gained through the establishment of co-ordinated switching between the two utilities.

Co-ordinated switching has already been implemented in several areas, and Hydro has provided switching training to Newfoundland Power employees responsible for switching Hydro disconnects at Bay L'Argent, Monkstown and Doyles.

Both utilities agree that maximum operating efficiencies would be achieved through a full implementation of coordinated switching. In order to facilitate this process both utilities agree that their respective Control Centre Superintendents finalize the list of agreed to switching locations, finalize a list of qualified switchers and agree on an implementation process.

Working Group # 10 - VHF Mobile Radio System

This Committee reviewed the infrastructure requirements to permit both utilities to talk with the other utility during switching operations and evaluated the replacement alternatives for a single system to service both utilities.

The working group determined that the only viable alternative for a single VHF system that would service the requirements of both utilities would be new infrastructure. The Committee recommended that when either utility is planning replacement of its' VHF then they would engage the other in discussions to possibly replace both with a common system.

Hydro is currently proposing the replacement of its VHF radio system beginning in 2004. Hydro and Newfoundland Power have met to discuss Hydro's planned VHF system replacement. A consultant has determined that the additional initial capital cost of adding Newfoundland Power to Hydro's system would be in the order of $3,000,000. However, Newfoundland Power has determined that it would not be cost-effective to participate in the development of a joint system as it is not planning a replacement of its VHF system at this time.

Hydro intends to seek approval in 2003 for the replacement of its system commencing in 2004. Newfoundland Power has agreed to provide Hydro with input to ensure the design of the new system does not unnecessarily or unreasonably preclude the possibility of Newfoundland Power utilizing the system in future.

Working Group # 11 - Inventories and Common Spares

This Committee reviewed materials management practices at both utilities to identify opportunities for sharing of inventories, cost reductions through standardization and potential benefits/constraints to shared warehouse facilities where practical.

Hydro and Newfoundland Power have a long history of sharing of inventory materials, whenever one utility has an immediate need that the other can meet. Both utilities maintain dedicated safety stock of critical items.

The process for the sharing of inventory materials has been included in the MOU for Sharing of Services and Equipment.

The Committee concluded that any savings realized through the combination of warehouse facilities in Whitbourne, Stephenville or Grand Falls/Bishops Falls would be off set by a corresponding increase in travel costs for the crews to pick-up materials.

Both utilities believe that inventory reductions may be achieved and material availability improved through further standardization of distribution and transmission line hardware, and will direct the appropriate personnel to review differences in standards in 2003 to identify any additional areas where standardization is feasible.

Working Group # 12 - 138 kV Transmission Line Maintenance for Central

This Committee undertook a review of the maintenance of 138 kV transmission lines in central Newfoundland to ensure that maximum reliability was being achieved and that there was minimum duplication of services. The Committee explored ways and means of sharing resources that included consideration of the effects of reorganization of maintenance responsibilities.

While the utilities were able to agree on the sharing of resources and materials as outlined in the MOU on Sharing of Services and Equipment, they could not reach consensus during the joint review on the issue of realignment of maintenance responsibilities.

Working Group #13 - Common Equipment and Engineering Standards

This initiative consisted of a review by four independent working groups who evaluated material and equipment specifications, design standards, construction standards and work methods for both utilities.

The mandate for these committees was to identify any potential cost reduction opportunities that may be derived from standardization.

The working group reviewing the Distribution line standards has achieved standardization in the areas where it is practical and appropriate. Some differences remain and both utilities agree that their respective engineering design groups will meet in 2003 to implement further standardization.

The working group, which reviewed the 69kv and 138 kV transmission line standards, developed a Wind and Ice Loading map for the entire system. This group reviewed the differences in design criteria for transmission line hardware and did not identify any significant opportunities for common design criteria. The primary reason for this lies in the different requirements for the bulk electrical system of Hydro and the distribution system of Newfoundland Power.

The concept of standard design for sub-station foundations and structures was evaluated. However, because of significant variances in conditions from site to site, specific design is often required.

Working Group # 14 - Joint Meter Shop Review

This Committee reviewed the meter shop operations of both utilities with the objective of reducing costs to the ultimate customer through the coordination of such activities.

In 1999, Newfoundland Power determined that the least cost approach for it was to contract out its meter testing and calibration. Hydro has acquired Measurement Canada Accreditation for its meter shop, which permits it to test, calibrate and seal meters.

Hydro presently has the 2002 contract for the servicing of Newfoundland Power meters and Newfoundland Power will be renewing the contract with Hydro for 2003.

Working Group # 15 - Technical Training

This working group explored opportunities for cooperation in the design, purchase and/or delivery of technical training programs that meet the strategic business needs and employee development priorities of both utilities.

While it was determined that the opportunities were limited, and the potential savings difficult to quantify, both utilities agree that this issue should be further explored in 2003.

3.0 Observations and Conclusions

A certain level of duplication of resources is inherent in an industry structure involving two separate corporations. Barring legislative change, some continuing degree of duplication is inevitable. In August 1998, the Government announced the Energy Policy Review, which included a review of the structure of the electrical industry in this Province. Until such time as the Energy Policy Review is finalized, further discussions between the utilities on such matters as service areas, or transfers of ownership of significant assets, are premature.

In terms of impact on operational effectiveness, the most significant opportunities for cooperation between Hydro and Newfoundland Power are at the generation and transmission level. For the most part, these opportunities are being realized on an ongoing basis. In other areas, as well, Hydro and Newfoundland Power cooperate on an ongoing basis to ensure the effective and efficient operation of the Island Interconnected electrical system.

The utilities have established a number of processes to address specific issues. These include system planning meetings that are generally held three times a year; annual joint utility meetings that provide a forum for major system stakeholders to discuss their concerns; the Inter-Utility System Reliability Committee, which meets bi-monthly to discuss reliability issues of common concern; and operations group meetings to discuss planned outages and coordinate maintenance and construction activities. These processes are described in Section 1 of this report.

Increasing attention has been given in recent years to identifying opportunities to reduce cost and improve service through collaboration at the distribution level. While some progress has been made along these lines, the degree of geographic separation of service territories will present a practical limit on achieving savings.

The areas evaluated during the 1997 review process did not result in the identification of significant savings in any area that could be achieved by enhanced coordination. The minor opportunities identified have been implemented or will be refined in 2003.The following areas have been identified for further review during 2003:

1. Explore the benefits of a common 1-800 number, for reporting power interruptions and emergencies, in light of both utilities now having a common service provider;

2. Review the print services recommendation to confirm the available savings and implement a process for Newfoundland Power to provide Hydro print services;

3. Develop and implement a formalized coordinated switching plan;

4. Review Hydro’s proposed VHF Radio System replacement for possible provision for future expansion to accommodate Newfoundland Power requirements.

5. Review the Distribution and Transmission Line hardware standards to identify any additional areas where standardization is feasible; and

6. Explore additional opportunities for joint training programs.

Cash Working Capital Allowance

Analysis of Semi-Annual Long-Term Bond Interest Payments

Newfoundland and Labrador Hydro

April 2003

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1. INTRODUCTION

In Newfoundland and Labrador Hydro's ("Hydro") last 2001 General Rate Application ("GRA"), Mr. Mark Drazen, the witness for the Town of Labrador City, proposed that the Cash Working Capital calculation should take into account the timing differences associated with semi-annual long-term bond interest payments and the receipt of the funds for their payment. At page 100 of Order No. P.U. 7 (2002 – 2003) the Board concluded,

> "At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue."

In Order No. P.U. 7 (2002 – 2003) section 19 (page 179), the Board ordered Hydro to file a study of the implications upon Cash Working Capital Allowance of the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. This report is filed in response to that order.

In considering this issue, Hydro consulted with its expert financial witness for its 2003 GRA, Ms. K. Mcshane. Ms. Mcshane of Foster Associates Inc. provided the comments for the section below, entitled Regulatory Considerations. In addition, Hydro re-examined the issue, in light of the methodology it uses in the estimation of the cost of debt. Hydro's approach, because it is iterative in nature, as opposed to being forecast on a projected debt schedule, automatically adjusts for the timing issues associated with semi-annual interest. Further detail on this is contained in the section entitled, Hydro's Approach to Cost of Debt Calculation.

2. REGULATORY CONSIDERATIONS

Regulators', in general, define the cash working capital allowance as the average amount of capital provided by investors, over and above the investment in plant and other specifically measured rate base items, to bridge the gap between the time expenditures are made and the time payment is received for service provided.

The following summarizes the regulatory posture in North America generally on including interest expense in the calculation of cash working capital:

> The treatment of funds relating to net operating income is subject to a wide difference of opinion in the evaluation of lead/lag study procedures. From a theoretical standpoint, operating income is earned when service is provided, and the operating income is the property of the investors in the company when earned. This view would recognize a cash working capital requirement for the lag in receipt of operating income. Such a requirement is equal to the revenue lag days multiplied by an amount equal to one day's operating income. The amount for interest or preferred dividends would not be offset, because those amounts are paid from funds belonging to investors (operating income).
>
> At the opposite end of the spectrum, on occasion parties have suggested that a source of cash working capital exists in the delay in disbursement of interest, preferred dividends, and dividends on common equity. Robert Hahne and Gregory Aliff, *Accounting for Public Utilities*, Newark, N.J.: Matthew Bender, 1998, 5-28.

2. REGULATORY CONSIDERATIONS (cont.)

The approach used to estimate the cash working capital allowance for Hydro in P.U. 7, and for Newfoundland Power since at least 1987, focuses solely on the day-to-day operating expenses, not the financing costs. This approach is similar to that which has been adopted for most of the major rate-base regulated utilities in Canada (e.g., BC Gas, the Ontario utilities, the Québec utilities[1], Nova Scotia Power and the NEB-regulated pipelines). The approach does not include depreciation or elements of the return on rate base in the calculation of cash working capital allowance. To quote a National Energy Board decision in this regard:

> The Board believes that an allowance for cash working capital is established to provide Westcoast's shareholders with a return on the funds they have invested, in addition to those invested in plant and inventories, which the Company requires to conduct its utility operations. These funds are typically used to pay employees' salaries and wages, purchase outside services and various other supplies and services which the Company requires in its daily operations. . . .
>
> With regard to the payment of interest on long-term debt and preferred share dividends, the Board is of the opinion that these items, which are not a function of operations but of the financing of the Company, are components of the rate of return. Furthermore, they relate to contractual obligations entered into between Westcoast's shareholders and the Company's other investors. As such, they do not involve the day-to-day operations of the Company, and do not properly belong in the calculation of the cash working capital allowance. (National Energy Board, Reasons for Decision, Westcoast Transmission Company Limited, August 1986.)

[1] The procedure was recently reviewed for both Gaz Metro (Decision D-99-11, February 10, 1999) and Gazifère (Decision D-2001-55, February 19, 2001). The Régie declined in both cases to include interest expense in the calculation of the cash working capital requirement.

2. REGULATORY CONSIDERATIONS (cont.)

The Alberta Energy and Utilities Board is the only Canadian regulator who includes all financial items in its calculations of the cash working capital allowance. It includes depreciation at a zero payment lag, recognizes a lead in receipt of revenues related to interest, preferred and common equity dividends, and includes the retained earnings component of the equity return at a zero lag (e.g., Decision U97065, October 1997). The Board concluded that the portion of the common equity return that was retained in the business should be treated similarly to depreciation, i.e., at a zero payment lag. The Board stated that depreciation and return were internally generated sources of funds used to finance plant additions. Although there was no certainty regarding the timing of the reinvestment, the assumption was made that the expenditures occur uniformly throughout the year, with a payment date equivalent to the service provision date.

The last point is critical. If interest expense is included in the lead/lag study, but there is no consideration of when cash is used for capital expenditures, the estimate of the total cash working capital requirement is understated.

3. HYDRO'S APPROACH TO COST OF DEBT CALCULATION

Hydro's approach to estimating its interest expense, further mitigates in favour of excluding a consideration of interest payment timing from the cash working capital calculation. Through an iterative approach to interest estimation, Hydro explicitly takes into account the timing differences between the payment of semi-annual interest, and the receipt of related revenues. By explicitly including the interest earned as a result of such timing differences, in the cost of debt calculation, the amount of interest expense included in the revenue requirement is reduced accordingly. An illustrative example of the methodology follows.

Table 1 illustrates the one year debt servicing cash flows associated with a $5 million bond issued at par, and carrying a semi-annual coupon rate of 10%.

TABLE 1

Monthly Cash Flows to Service 10% Coupon $ 5 Million Bond issued at Par

Month	Debt Service Cash Flow
1	
2	
3	
4	
5	
6	250,000
7	
8	
9	
10	
11	
12	250,000

3. HYDRO'S APPROACH TO COST OF DEBT CALCULATION (cont.)

Mr. Drazen's argument is that while the annual cost of debt arising from this is 10%, the total $500,000 interest expense would be factored into rates, and would produce a revenue cash flow stream that is received monthly, hence producing a stream of cash flows as in Table 2.

TABLE 2

Monthly Cash Flows Accruing Through Rates

MONTH	REVENUE CASH FLOW $
1	41,667
2	41,667
3	41,667
4	41,667
5	41,667
6	41,667
7	41,667
8	41,667
9	41,667
10	41,667
11	41,667
12	41,663
Total	500,000

3. HYDRO'S APPROACH TO COST OF DEBT CALCULATION (cont.)

Mr. Drazen argues that based on Tables 1 and 2, cash flows related to revenue are received in advance of debt service. This is not the case for Hydro, because Hydro's interest and cost of debt model is iterative. This means that advance cash flows, such as those referred to in Table 2, are iterated back through the model in the determination of Hydro's final cost of debt. Hydro's model assumes that such advance cash flows are available to reduce short-term debt requirements. For simplicity, the effect of this, assuming that such advance funds were invested at a rate of return[2] is illustrated in Table 3.

TABLE 3

Iteration of Timing Differences

Month	Revenue Cash Flows	Investment Account Earnings	Debt Service Cash Flow	Investment Account Balance
1	41,667	174		41,840
2	41,667	348		83,855
3	41,667	523		126,045,
4	41,667	699		168,410
5	41,667	875		210,952
6	41,667	11	250,000	2,630
7	41,667	185		44,481
8	41,667	359		86,506
9	41,667	534		128,707
10	41,667	710		171,084
11	41,667	886		213,637
12	41,663	22	250,000	5,326
Totals	**500,000**	**5,326**	**500,000**	

[2] Assumed to be 5% for the purposes of this illustration.

3. HYDRO APPROACH TO COST OF DEBT CALCULATION (cont.)

Hence, because of the nature of Hydro's methodology, the reported cost of debt in this instance, instead of 10%, is 9.9%, calculated as follows:

Net debt outstanding = $4,994,674 (Principal outstanding less Investment Account - $5,000,000 - $5,326)

Interest cost = $494,674 ((Semi-annual interest less interest earned - $500,000 - $5,326)

Cost of debt = 9.9% (Interest cost divided by net debt outstanding)

Consequently, Hydro's weighted average cost of capital, and therefore its required return on rate base, is reduced in proportion to the benefit received from the timing of payments related to semi-annual interest.

3. SUMMARY

If interest payments are to be included in the lead/lag study, all items related to financing need to be included. If the cash working capital allowance is interpreted in the broad sense of measuring the full extent to which investors have financed the full cost of service, leads and lags on all elements of the return of and on capital need to be taken into account.

Hydro recommends to the Board that it continue to approve the methodology utilized by Hydro for the determination of its cash working capital allowance. That approach focuses on Hydro's operating expenses and measures the additional capital provided by investors to sustain day-to-day operations between the time service is provided and payment received.

This analysis concludes that, while there may be a theoretical validity to an approach which considers all financial terms, including depreciation, that approach adds a degree of complexity which is unwarranted for the purpose of estimating a reasonable cash working capital allowance, particularly given that Hydro's method of forecasting interest expense and the cost of debt already reflects the timing of semi-annual interest payments.

Non-Regulated

Operations

Newfoundland and Labrador Hydro

December 2002

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DEFINITION AND PROCEDURES

Non-Regulated Operations Definition:

All costs associated with any asset which is not used and useful in the generation, transmission and distribution of electrical power and energy by Newfoundland and Labrador Hydro within the Province of Newfoundland and Labrador; activities exempted by specific legislation; and costs specifically identified by the Public Utilities Board as being non-recoverable from rate payers.

Procedures:

1. All non-regulated operations must be reported to the Corporate Controller who will ensure that business units and if applicable, work orders are set up to track costs. Consultation will take place with the Rates & Financial Planning Section to ensure that their requirements for a cost of service study are met.

2. In the event of any uncertainty as to whether an activity/cost is to be non-regulated, details should be referred to the Corporate Controller for a decision.

3. The Corporate Controller will consult with the Rates & Financial Section on all requests for clarification so as to ensure the integrity of the cost of service data.

LIST OF NON-REGULATED ACTIVITIES

To date the following activities/costs have been determined to be non-regulated:

1. All activities associated with the following subsidiary companies:
   (i) Churchill Falls (Labrador) Corporation Limited
   (ii) Lower Churchill Development Corporation Limited
   (iii) Gull Island Power Company Limited
2. Supply of power to the Iron Ore Company of Canada
3. All Export Sales
4. New Business Development
5. All activities/costs associated with the Labrador Hydro Project negotiations/ activities re the Lower Churchill hydroelectric developments
6. Other Specific Non-Regulated Costs defined in Section 6 of this policy

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED

Cost Recoveries Agreement

The services provided to Churchill Falls (Labrador) Corporation (“CF(L)Co) by Newfoundland and Labrador Hydro (“Hydro”) are rendered according to an agreement (“Cost Recoveries Agreement”) between the parties, which is reviewed annually to reflect any changing conditions in the services to be provided. The recoveries are estimated at the beginning of each year based primarily upon the prior year’s actual costs plus any adjustments that are required as a result of updated information concerning services to be provided in that year. In addition a year-end adjustment is calculated based on a review of actual costs and services incurred/rendered by Hydro.

CF(L)Co is also responsible for providing services to Twin Falls Power Corporation Limited (Twinco) and the cost for these services is borne by CF(L)Co.

Cost Allocations

Specific work orders have been created in most areas of Hydro to capture the costs of providing services to CF(L)Co. For the most part, salary costs are apportioned to these work orders based on timesheet reporting using a billing rate to cover salary costs and payroll related benefits. The ratio between actual salaries reported in the work order and total actual salaries for the Business Unit is generally used to allocate other applicable costs for the Business Unit.

The following are the various departments that provide services to CF(L)Co:

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

a) Management

Salary costs for Executive Management services for CF(L)Co are recorded using time sheets. The ratio of the total dollar value of time reported to the total salary dollars of Executive Management is determined and applied to salary costs for Executive Assistants and other applicable expenses.

The Executive Assistants in this department do not prepare time sheets for CF(L)Co services. The costs for these employees are allocated based on the percentage calculated from the time reported by Hydro's Executive Management. Since their efforts are a support function for Executive Management, this is felt to be a reasonable allocation of the cost of this staff.

b) Legal

Salary costs for the services provided to CF(L)Co by the legal staff are recorded using time sheets. The ratio of the total dollar value of time reported to the total salary dollars of legal staff is determined and applied to other applicable expenses.

c) Internal Audit

The Internal Audit Department determines an annual audit plan as part of the annual update of the Five Year Internal Audit Plan - CF(L)Co Internal Audit services are provided in the areas of Plant Maintenance, Plant Operations, Line Maintenance, Air Services, Warehouse, Municipal Maintenance, Fire and Security, Environmental Compliance, Hydro-Quebec Power Billings and Commercial Services. Payroll costs incurred in providing internal audit services to CF(L)Co are recorded using time sheets.

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

d) Engineering Services

This department provides services in all engineering disciplines and covers such items as:

a) Design, Construction and Project Management
b) Engineering studies, technical specifications and construction coordination
c) Tender preparation and analysis including interaction with consultants
d) Review and resolution of maintenance problems

Payroll costs incurred in providing engineering services to CF(L)Co are recorded using time sheets.

e) Environmental Services

The Environmental Services & Properties Department's activities relating to CF(L)Co include the auditing for compliance with government regulations and corporate policy, obtaining permits and approvals for proposed programs and advising CF(L)Co on environmental matters.

Payroll costs incurred in providing environmental services to CF(L)Co are recorded using time sheets.

f) Human Resources

Human Resources is responsible for the administration and coordination of all employee related services, employee benefit programs, pensions, recruitment, training and payroll as well as the maintenance of the corporate human resources database. Human Resources also administer the performance appraisal system, salary surveys and maintains a current organizational chart.

Payroll costs incurred in providing Human Resources services to CF(L)Co are recorded using time sheets.

<u>1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED</u> (cont'd.)

g) Labor Relations & Safety

The Labor Relations & Safety Department is administratively responsible for the activities of the Human Resources Section in Churchill Falls and directly provides services relating to the negotiation and administration of collective agreements, the resolution of grievances and all union/management communications. The Department also directly provides Occupational Health services including wellness, disability and sick leave management, and medical screening as well as coordinating corporate efforts with regard to employee safety.

Payroll costs incurred in providing Labor Relations and Safety services to CF(L)Co are recorded using time sheets.

The Labor Relations Specialist (St. John's) does not prepare time sheets for CF services since these duties are performed by the Superintendent of Human Resources and Administration in CF(L)Co. The percentage calculated for Labor Relations takes this into account.

h) Financial Planning

Rates & Financial Planning Section (RFP) provides services to CF(L)Co for those activities that facilitate the production, review and distribution of CF(L)Co's annual Long-Term Financial Plan. As well, RFP is required to provide long-term financial planning and analyses for various scenarios up to and including timeframes to the end of the fiscal year in which the Power Contract expires, namely 2041. RFP is responsible for ensuring the CF(L)Co long-term planning model is updated and maintained in a current state from both a software and hardware perspective.

Payroll costs incurred in providing Financial Planning services to CF(L)Co are recorded using time sheets.

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

i) Risk Management & Public Relations

The Corporate Affairs and Risk Management Department provides corporate external and internal communication services as well as the placement, policy and claims administration, risk control and risk financing of the corporate insurance program.

Payroll costs incurred in providing Risk Management & Public Relations services to CF(L)Co are recorded using time sheets.

j) Controller

The Controller's Department provides accounting services to CF(L)Co through the Financial Reports & Budgets and Capital Reports & Disbursements sections. The most significant accounting services provided include the recording of actual costs in the general ledger, accounts payable and accounts receivable processing, account reconciliations, financial and capital reporting both internally and externally, as well as maintenance of the capital asset records. The Controller's Department is responsible for and provides assistance to various personnel in the preparation and review of the capital and operating budgets for CF(L)Co. This department, through the Module Support section, also provides advice and assistance to CF(L)Co in the use and maintenance of the various JDE system modules. The Controllers Department handles all matters relating to both federal and provincial taxation authorities for CF(L)Co, calculates preferred dividends and prepares various reports as required in the Shareholders Agreement.

Payroll costs incurred in providing Controller's services to CF(L)Co are recorded using time sheets.

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

k) Treasury

The Treasury Department is responsible for all debt and cash management activities for CF(L)Co.. Debt servicing includes determination of the interest subsidy, Contingent and Voluntary redemption amounts and the purchase and investment of US funds. Compliance with certain aspects of various contracts such as the Bond Purchase Agreement, the Guaranteed Winter Availability Contract, the CF(L)Co Power Contract with Hydro Quebec, and the Recapture Agreement with Newfoundland and Labrador Hydro, is ensured. Responsibilities under these agreements include issuance of invoices to Hydro Quebec and Newfoundland Hydro and calculations and administration of all aspects of the four-year review of the Annual Energy Base. Treasury also prepares the CF(L)Co interest expense budgets, makes investment decisions, and recommends common dividend levels. Audit work papers are prepared and reconciled to the General Ledger and explained to the Auditors.

Payroll costs incurred in providing Treasury services to CF(L)Co are recorded using time sheets.

l) I S & T

IS&T provides assistance and support to CF(L)Co in the areas of Software Applications, Planning and Integration and Business Solutions. This department is also responsible for the maintenance and administration of the Corporate Computer Operations and provides technical support to CF(L)Co's on-site analysts.

At present, IS&T costs, except for telephone costs for Hydro Place, are allocated based on the ratio of CF(L)Co personal computers to the total personal computers in the Hydro Group.

Satellite communications charges are billed directly to CF(L)Co by the supplier and do not form part of this agreement.

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

m) Materials Management & Administration

The Materials Management & Administration department coordinates all efforts involved in the procurement process activities for CF(L)Co including tendering, purchasing and contract administration. Materials management also provides training, advice and assistance to site personnel in the use of the Materials module of the JDE system. Purchasing activities for the Commercial Services department in CF(L)Co are performed at Site by the staff of the Commercial Services department and as such do not form part of the Cost Recoveries Agreement.

Payroll costs incurred in providing Materials Management services to CF(L)Co are recorded using time sheets.

Administration provides such services as library, mail, forms and office supplies as well as the receipt of goods for those employees involved in CF(L)Co activities in St. John's.

Currently the administrative costs within Hydro Place (such as postage, heat and light, maintenance materials, etc.) are allocated to CF(L)Co on the basis of the equivalent complement percentage.

The "equivalent complement" can be defined as the equivalent number of employees required to provide those services currently provided to CF(L)Co by Hydro under the Cost Recoveries Agreement. This calculation consists of three steps.

In step one of this calculation, for most departments, the total salaries for permanent employees recorded in the CF(L)Co work orders are expressed as a percentage of total permanent salaries for that department.

1. (i) CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED (cont'd.)

m) Materials Management & Administration (cont'd.)

In step two this percentage is multiplied by the total permanent complement for that department, adjusted for employees not involved in providing services to CF(L)Co or employees who are not resident at Hydro Place to arrive at the equivalent departmental complement.

In step three of the calculation, the equivalent departmental complements are totaled and divided by the total permanent complement for Hydro Place to arrive at the Equivalent Complement percentage.

This calculation must be performed annually as part of the year-end review of actual costs and services incurred by Hydro and the effect should be included in the year-end adjustment.

n) Maintenance Analyst

The Maintenance Analyst provides expertise in various functional processes of the organization to department managers and line employees of CF(L)Co, with special emphasis on the Maintenance Module of JDE.

Payroll costs incurred in providing the Maintenance Analyst's services to CF(L)Co are recorded using time sheets.

o) Drafting Support

Services from this section are provided only as part of special projects and time sheets are used to record incurred payroll costs.

1. (ii) LOWER CHURCHILL DEVELOPMENT CORPORATION LIMITED

Although this corporation is primarily inactive, minimal costs for such items as an annual report and an external audit are being incurred and Business Unit #1953 has been set up to capture these costs. Any employee involved in this venture will charge their time to a standard work order set up for this business unit by completing a time sheet. The following object accounts have also been set up within this Business Unit.

Description	*Object*
Transferred in Salaries	6035
Materials Maintenance	6105
Professional Services	6264

1. (iii) GULL ISLAND POWER COMPANY LIMITED

This corporation is primarily inactive but some costs are being incurred by Hydro and Business Unit #1954 has been set up to capture these costs. Any employee involved in this venture will charge their time to a standard work order set up for this business unit by completing a time sheet. The following object account has been set up within this business unit.

Description	*Object*
Transferred in Salaries	6035

2. SUPPLY OF POWER TO THE IRON ORE COMPANY OF CANADA

Power and energy sales to the Iron Ore Company of Canada (IOC) are a non-regulated activity.

IOC is a customer on the Labrador Interconnected system and consequently the portion of costs associated with this customer are derived from the Cost-of-Service. Rates charged this customer are based on a negotiated contract and do not require approval of the PUB.

In order to determine our regulated versus non-regulated net income, a revenue adjustment account has been set up in Business Unit 1952 and this adjustment will be equivalent to the margin Hydro earns for this customer. The annual adjustment will be based on the final cost of service for 2002 and in consultation with the Rates & Financial Planning Section, adjustments may be required for significant changes in load, major cost changes, actual Cost of Service studies, actual revenue requirements, etc.

3. ALL EXPORT SALES

Hydro meets the power and energy requirements for the Labrador Interconnected System primarily through an agreement with CF(L)Co. Under that agreement Hydro purchases recall power and energy up to a maximum of 300MW and 2,362 GWh annually. Power and energy surplus to meeting the needs of the Labrador Interconnected System is sold by Hydro to Hydro-Québec.

Business Unit #1950 has been set up to capture the revenue and costs associated with this venture and the following object accounts have been set up.

Description	*Object*	*Description*	*Object*
Sales Revenue	5025	Power Purchased Interest	7335
Interest Income	7705	Transferred in Salaries	6035
Power Purchased	7325	Dividends	8300

Any employee involved in this operation will allocate their time to a standard work order set up for this business unit by completing a time sheet.

System Operations will allocate the power purchase costs (budget, forecast and actual) as well as the interest associated with the power purchases.

The Board of Directors has authorized the payment of monthly dividends to the Province for the actual monthly net income from recall sales to Hydro Québec. The ratification of dividend payments is made at subsequent board meetings. Dividends are to be paid to the Province on the same day that funds are received from Hydro Québec and CF(L)Co is paid for the purchased power. For example January's net income would be paid out in February, February's net income paid out in March and so on.

Dividends associated with net profits on export sales are to be recorded in the same year that the net income is recorded for accounting purposes. Dividends are to be paid as outlined above and in December of each year a dividend would be declared based

<u>3. ALL EXPORT SALES</u> (cont'd.)

on our best estimate of net income for December but payable in January upon receipt of funds from Hydro Québec. From an accounting perspective, this will permit a dividend payable to be set up at year-end. Any difference between actual and forecast net income should be minimal and any final settlement would be done as a separate dividend in January.

4. NEW BUSINESS DEVELOPMENT

Business Unit #1956 has been set up to capture all costs related to non-regulated new business developments and work orders will have to be set up to track each activity. If an activity develops into a new business then a new business unit will be established. The following object accounts have been set up in this business unit:

Description	*Object*
Transferred in Salaries	6035
Professional Services	6264
Travel	6505

5. LABRADOR HYDRO PROJECT

Historically, Hydro has considered all costs associated with further development of the Churchill River in Labrador to be a non-regulated activity and therefore, not recoverable from ratepayers.

Capital Job Cost #10250 has been set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead and these costs form part of Hydro's construction work in progress. A separate payroll has been set up to accommodate employees hired exclusively for this project with all costs charged to the job cost. Hydro employees use time sheets to charge their time to the project. Wherever possible, supplier costs are clearly identified as being related to this project so that the costs are properly recorded.

6. OTHER SPECIFIC NON-REGULATED COSTS

Business Unit #1955 has been set up to capture non-regulated costs. Those identified to date are as follows:

a) Contributions and Donations

Expenditures for charitable donations, community and charitable advertisements, street light subsidy and scholarships are not allowed as regulated expenses.

All of these costs are to be recorded in this business unit in object #6610 and each region/department will use a work order to monitor their expenditures.

b) Advertising

Regulated advertising expenses are limited to matters relating to conservation, safety and consumer information. Advertising for corporate image building is not a regulated expense. Object account #6225 has been set up to record non-regulated advertising.

c) Companion Travel Costs

On occasion, Management approves the cost of a Hydro employee's companion attending a corporate function. These costs are to be recorded in this business unit in object account #6505.

d) Muskrat Falls

Hydro presently has some fully contributed capital assets in Labrador that are associated with Muskrat Falls, a non-regulated activity, and maintenance costs are incurred. These maintenance costs are to be recorded in this business unit and tracked by means of a work order.

6. OTHER SPECIFIC NON-REGULATED COSTS (cont'd.)

e) Big Brook and Barr'd Harbour

Both of these communities are located on the Northern Peninsula and receive electricity under a special arrangement approved by Government in the early 1970's. Hydro collects no revenue from either community but does supply diesel generation equipment and performs major maintenance. Consequently, this activity has been deemed non-regulated. Costs for these activities are recorded in this business unit and tracked by means of a work order.

Review of Rate Design for Newfoundland Power

April 9, 2003

Report prepared by:

Stone & Webster Management Consultants, Inc.

Proprietary and Confidential

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1. Background

Discussions with respect to the proper rate structure for service provided by Newfoundland and Labrador Hydro (Hydro) to Newfoundland Power (NP) have occurred over a number of years. NP has been, and continues to be, billed on an energy only basis in its rate structure. During NP's rate hearing in November of 1989, discussions occurred regarding the alternatives to the energy only rate structure that Hydro was using to bill NP. As a result of the discussions, the Board of Commissioners of Public Utilities (Board) issued a report in January of 1990 summarizing the issue with this statement: "This rate form makes it difficult for the Company (NP) to send its retail customers proper pricing signals." During the hearing, NP witnesses explained that the "energy only" rate causes NP problems in trying to design rates that send proper pricing signals to their General Service Customers.

During Hydro's 1990 rate hearings, the issue of a demand versus an energy rate was again raised by NP, in which NP indicated that in order to implement "effective Demand-Side Management (DSM) programs, customers must receive proper pricing signals". The energy only rate was perceived to give NP little incentive to engage in DSM activities that reduce peak load.

The Board, in its June 1990 report to the Minister, recommended: "at its next rate hearing Hydro present whatever information it may have with regard to a rate with a demand charge component, for discussion and determination of a date for filing a rate proposal".

In response to the board directive, at its 1992 rate hearing, Hydro proposed a three-part rate (demand rate, energy rate, and customer charges) to become effective January 1, 1993. Considerable discussion took place at the hearing focusing on Hydro's inclusion of a twelve-month ratchet in the demand rate. While Hydro believed that the ratchet was necessary, NP argued that it was of little use and that NP would be unable to pass a ratchet signal on to its customers. NP proposed instead that its billing be based on actual monthly demand with any variation from Cost of Service (COS) to be included in the Rate Stabilization Plan (RSP) to ensure that Hydro collects its revenue requirements. Hydro suggested that some form of weather normalization could be used in order to reduce the impact of a twelve-month ratchet.

The Board, in its April 13, 1992 report to the Minister, recommended "that Hydro and NP develop an acceptable rate form for review by the Board at the hearing to be held on Hydro's Cost of Service Methodology".

Following the Board's 1992 report, Hydro and NP held several meetings with the objective of resolving the outstanding issues by developing a mutually acceptable rate structure. While several proposed demand rate alternatives were discussed and evaluated, no mutually acceptable agreement was reached.

This issue was raised again at NP's 1996 general rate proceeding and the Board ordered NP to follow the direction given in the 1993 COS Methodology report to consult with Hydro on the development of an acceptable rate form containing an appropriate division of demand and energy costs. No time limit on the development of a rate was suggested in the Board's order.

In the 2002 Application by Hydro for a General Rate Review, the Decision and Order of the Board, Order No. P.U. 7 (2002-2003) June 7, 2002, directed Hydro to provide further insight and an update on the matter of a demand charge component to the NP rate structure. The Order notes that at the 1992 COS hearing, Hydro and NP informed the Board that the development of an alternative rate form for NP was not yet finalized. In the 2002 Application for General Rate Review, Hydro stated that "Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate." A letter from NP to Hydro submitted in evidence outlines NP's then current position:

> *"It is Newfoundland Power's view that, while a demand-energy rate may be theoretically desirable in many circumstances, introducing such a rate structure into the power purchase arrangement between Newfoundland Hydro and Newfoundland Power is neither necessary nor desirable in the current environment".*

The Board remanded the issue to Hydro and NP, requiring further supporting evidence before making a decision on the demand and energy issue. The Board is expected to address the issue at Hydro's next general rate hearing scheduled for 2003. The specific nature of the Board decision follows:

> *"The Board finds it is not in a position at this time to make a final determination on the issue of whether an energy only rate is appropriate for purchase of power by NP from Hydro. The Board has noted the position of the parties but further evidence will be required from both NP and Hydro before making a final decision. If the Electricity Policy Review currently underway does not address this issue as put before the Board at the pre-hearing conference in September 1998, the Board will address it at Hydro's next general rate hearing. At that time*

the Board will expect Hydro to file supporting evidence with its application to address the demand energy pricing issues raised in this hearing."

1.1. Key Issues

The history provided in the previous section provides a background of the issues, objectives, and concerns on behalf of all of the parties involved in the energy demand rate debate. Each of the key issues are summarized in the following four paragraphs:

1. **Send a correct price signal to all parties.** From the inception, a continuing concern has been the ability to encourage DSM**.** In this report, DSM is viewed in a broad and all-encompassing sense; DSM includes not only energy efficiency and energy conservation, but also peak demand control programs. Therefore in this study the term Load Management (LM) is used to refer to these activities.

2. **Ensure that all parties (Hydro and NP) remain revenue neutral and avoid earnings (revenue) volatility**. Subsets of this issue include:

   - Avoiding a windfall or penalty to either utility due to abnormal weather;
   - Protecting ratepayers from artificial or short-term cost increases; and,
   - Minimizing revenue volatility, which may result if a demand rate is established and a portion of the revenues is removed from the stabilizing influence of the RSP.

3. **Provide NP an incentive to minimize the island peak.** A demand rate can provide NP with a direct incentive to reduce peak through the use of its own generation during peak. Through the use of a demand rate, NP in turn can provide incentives to its customers to reduce peak through rates or other cost effective means.

4. **Rationalize the rate approach with the treatment of NP's generation in the COS.** Hydro's current COS methodology provides NP with a credit for its generation capacity. A demand rate may impact how NP wishes to utilize its generation, thereby affecting costing, or Hydro may wish to offer an alternative treatment of NP generation.

These issues and their implications are explored further in this report in order to provide Hydro with sufficient information to assess the development of an alternative rate structure for service to NP.

2. Current Rate Structure

Hydro employs a cost of service methodology that either allocates costs to the various customer classes based on energy, demand, and customer charges, or directly assigns customer specific cost. Hydro's methodology is representative of standard industry protocols. Hydro's revenue requirement from NP is comprised of demand, energy and customer classifications in the cost of service; however the total revenue requirement is divided by the projected test year kWh to arrive at an energy only rate.

There are generally two types of price signals: energy and demand. The energy price signals the need to either use or conserve *natural* resources. The demand price signals the need to either use or conserve *capital* resources.

The current energy only rate does provide an indirect signal to NP. First, the energy rate, excluding the impacts of the RSP, provides a signal that the less energy consumed, the lower the overall electric bill. Since NP is not the ultimate end-user, it can choose whether or not to respond to the price signal by providing an appropriate rate structure to its customers. In addition, the current rates provide a signal because NP is aware that its own peak load is a key driver of the cost that is allocated to it. Therefore, if NP reduces its coincident peak by means such as LM from its customers, it will receive a lower demand allocation in Hydro's cost of service. However, there is a delay in this result since the impact of the lower demand may not be recognized until a rate hearing takes place and new allocation factors are determined. This price (demand) signal therefore is indirect at best since it can take significant time to actually see the impacts in rate structure.

3. Revenue Stability and Price Volatility

In this section, two key rate design issues are discussed relative to revenue stability and price volatility including 1) weather impacts on volatility, and 2) the impact of the rate stabilization plan on rate structure decisions.

3.1. Volatility Due to Weather

One of the concerns about implementing a demand rate is volatility in revenue resulting from weather variations. Hydro's peaks can vary by as much as 100 MW in any given year due solely to weather variations, which might result in a revenue and profit windfall, or a penalty to either utility. Should this be a concern in the final rate design (including a demand rate), then incorporating a weather adjustment could minimize volatility in revenues resulting from weather conditions.

To demonstrate the weather impact, the forecasted and actual peak could be approximately equal, but milder than normal weather conditions occurring at the time of actual peak may result in a higher weather-adjusted peak, and vice versa. Hydro currently uses a weather adjustment model that separates weather-based peak changes from changes that may be attributable to actual growth in load requirements from customers. If needed to reduce revenue volatility, a similar adjustment process could be incorporated into the final rate design. An example of this phenomena and its meaning are discussed more fully in Appendix 1. The important point of this discussion is that the NP rate can be designed to send a signal based on a demand that is relatively free of weather impacts by incorporating explicit adjustments.

3.2. The Rate Stabilization Plan

The Rate Stabilization Plan (RSP) was established for Newfoundland Power and Island Industrial Customers (IC) to smooth rate impacts resulting from variations between actual results and estimates included in the test year cost of service. The RSP accounts for differences specifically for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (NP and IC); and
- Rural rates.

Hydro tracks the components of the plan monthly, comparing actual results with the test year parameters and crediting or charging the plan with any identified differences. The annual balance in the plan is recovered from both NP and IC through an automatic adjustment in rates. As of December 2002, the RSP balance requiring future recovery is approximately $125 million. This balance is primarily attributable to the large escalation in the price of oil.

The intent of the RSP is to provide stability to Hydro and its customers by deferring the collection or refund of variations in the components listed above. As evidenced by the current deferral in collection of extremely high fuel prices, Hydro's RSP keeps its stabilized customers from receiving an immediate price signal. Providing a price signal and maintaining rate stability have offsetting results. In order to provide a demand price signal, it is necessary to have some "at risk" revenue for the utility.

The load variation component of the RSP ensures that Hydro has revenue stability in its energy sales. Since NP's entire revenue requirement is collected by means of an energy rate, any portion that is decoupled from the energy rate (and thus from the RSP) and collected in a demand charge may introduce some revenue uncertainty to Hydro. Mechanisms such as a ratchet clause or minimum-billing level may be used to mitigate some of this uncertainty. Balance can be achieved between the conflicting objectives of sending an appropriate price signal and revenue stability.

4. Treatment of Newfoundland Power Generation

NP's generation benefits the island interconnected system and in Hydro's cost of service, a demand credit is given to NP to recognize this. With the introduction of a demand component to the NP rate, the treatment of the generation credit becomes more prominent and the question arises as to whether present methodology should be continued or perhaps a change is warranted. Under the current cost of service methodology, NP is credited for all of their available generation, less reserve; this results in a lower demand cost allocation to NP. Also, load factor is used in the cost of service to classify costs between energy and demand. In this load factor calculation, NP's coincident peak net of its capacity credits is used. This calculation impacts the demand/energy split and consequently the allocation of functionalized generation and transmission costs among classes of service as well. Thus, in developing a demand rate, the treatment of the generation credit must also be considered.

This section describes alternative treatments for NP's generation, assuming a demand rate has been implemented. These options include:

- Option A - Continue the current costing treatment and apply the generation credit to the native load to determine the billing demand; this option credits NP for all of its generation sources;
- Option B - Apply a thermal generation credit to Coincident Peak (CP) for costing; but bill for demand supplied by Hydro plus any NP thermal generation operating and supplying power to the network at the time of Non-Coincident Peak (NCP); this option builds NP's thermal sources into the credit and treats its hydro sources separately; and,
- Option C – Remove the generation credit for both costing and billing purposes.

Each option is further described in the following paragraphs.

Option A

Under the current COS methodology, NP receives a credit of 125 MW for its generation (which already includes a reduction for system reserve requirements). This credit is used to reduce NP's native peak load for costing purposes. This adjusted NP peak is used to calculate the ratio of NP to the total system peak; the net result is to reduce the overall revenue requirement allocated to NP. The adjusted peak is also used to calculate the system load factor (LF) and results in an increase to the LF.

Billing demand would be calculated as NP's native non-coincident peak load less the 125 MW generation credit.

Option A ensures that NP receives the capacity credit regardless of actual generation actions at the time of Hydro's peak. This costing approach is similar to the current costing methodology. However, a significant advantage of this option is that in assuring that NP will receive the full capacity credit regardless of actual generation, it does not signal the need to operate its generation at peak, thereby permitting it to maximize energy from its hydraulic generation.

A potential disadvantage of this option is that it values the generation credit based on capacity values rather than actual generation at peak. Also, billing demand is calculated rather than directly metered.

Option B

NP has 94 MW of hydraulic generation capacity and 54 MW of thermal capacity. This option provides a costing generation credit for only the thermal generation, placing the onus on NP to forecast its peak requirements from Hydro net of its probable hydraulic generation.

NP would be billed based on its maximum metered demand, with any of NP's thermal generation at time of peak added back, since the thermal credit has been applied to cost allocation. An advantage of this option is that since billing demand is dependent upon actual hydraulic generation, the economic decision rests with NP as to how its hydraulic generation is managed. Also, under this option there is no economic incentive for NP to run its more costly thermal generation.

However, a significant disadvantage under this option is the potential for NP to operate its hydraulic energy production to shave peak and consequently increase the potential of spilling water. There is also some potential risk or gain to Hydro when actual hydraulic generation is greater or less than forecast.

Option C

No generation credit will be applied to NP's demand for either costing or billing demands. The economic decision rests with NP as to how all of its generation resources are managed. It may be possible to offset potential NP thermal generation costs with lower Holyrood costs, through billing and operational arrangements. Maintaining least system cost in this manner would essentially equate to Option B, although costs may shift among customer classes. Other than the fact that billing is based on an actual metered number and the treatment of NP is consistent with the IC, there are few advantages for Hydro in Option C.

The principal disadvantage under Option C relate to a loss in revenues to Hydro as the result of NP running its hydraulic and thermal generation in order to reduce its load at the time of the system peak. These actions can result in water spill as well as an increase in fuel costs to the system. In this regard, an analysis was performed to assess the potential impact to NP and to the system as a result of NP running its generation for the purpose of peak shaving. This analysis is contained in Appendix 2, attached. A key disadvantage of this Option is that resource operation is not optimized for the island.

An illustration of these options is provided in Appendix 3 of this document.

4.1. Recommendation

In consideration of the relative merits of each alternative, Option A is recommended as the preferred option, in that it eliminates virtually all of the variability in load that is dependent on how NP operates its resources, with the result of measuring pure customer load profile. In providing an unfettered price signal to consumers, Option A is the most consistent with the price signal requirements identified in Section 1 as well as the rate design principles discussed in Section 6.

5. Potential Impact of Load Management

One economic function of a demand rate structure is to inform a customer about the fixed costs in a power system and to illustrate the impact of a change in demand on existing system costs. This is broadly referred to as a demand price signal and it generally has merit since capacity costs are significant. The potential for a customer to utilize this price signal involves the interaction of and consideration of the:

- level of the demand rate,
- potential for load management in the customer's end-use equipment profile,
- cost of procuring the load management potential, and
- customer's receptiveness to utility sponsored load management programs.

Electricity has approximately a 50 percent market share of residential space heating in NP's service territory, with similar penetration for the general service market. Thus electric space heating dominates the winter peak demand profile of NP. However, electric heat can be a problematic end-use load for utilities to manage.

Perhaps more relevant in the consideration of load management is the fact that electric hot water heaters have approximately 85 percent market share in NP's territory. Electric water heaters have a long history of being manageable loads for utilities since the appliance is, by definition, a storage device and thus customer service need not be impaired despite utility management of the timing of its peak demand. The technical potential for load management of only electric hot water heater loads is large. In rough numbers, there may be about 150,000 electric hot water heaters in NP's service territory and the utility standard estimate for diversified demand is about 1 kW per unit, or roughly 150 MW of load that is available for control in total. With controls or cycling of water heaters, achievable load management potential would be significantly lower than the technical potential, reflecting the interaction of economic and market factors noted above. Typically the largest load management opportunities are derived from commercial and industrial facilities rather than residential facilities, and in several U.S. jurisdictions, demand rates have resulted in significant load shape shifts when targeted at large users.

6. Rate Design Issues

6.1. The Nature of Rate Design (In Brief)

Ratemaking encompasses the fair allocation and collection of costs from customers for the services that are provided. A cost of service study allocates costs to customer classes based on cost causation principles and rates that are reflective of these allocated costs are the most widely recognized measure of rates that are equitable and non-discriminatory.

Hydro's cost of service develops unit costs for each of its customer classes, including NP. These unit costs, which are expressed in terms of $/kW/month, $/kWh, and $/bill are not rates per se, but serve as a valuable guide in the rate design process. These derived unit costs are not necessarily used as actual rates because there are considerations other than cost that come into play. These other considerations include concerns such as:

- Competition,
- Conservation and load management (energy and capital),
- Social welfare (lifeline rates),
- Value of service, and
- Historical rate relationships (rate shock).

In designing rates, it is generally recognized that not all of the utility's objectives may be able to be met simultaneously and tradeoffs are often required. One common example of this is the need to sell versus the need to conserve. Thus, there is the requirement to balance objectives as well as the interests of all stakeholders, and it is for this reason that rate design has been characterized as an art as well as a science.

6.2. Demand / Energy Rate Considerations

In introducing a demand component in Hydro's rate to NP, three principal objectives are:

- To provide an appropriate cost-based price signal,
- To maintain revenue stability, and
- To provide an incentive to control island peak.

The first two goals can be seen as being at odds with each other. This is especially true in Hydro's case. Hydro currently serves NP on an energy-only rate with energy revenues stabilized through the RSP, such that the introduction of a demand component will effectively destabilize a portion of its projected revenue stream. Thus, in developing an appropriate demand rate structure for NP, Hydro must carefully weigh a number of factors, including the demand and energy relationship, and the appropriate basis for the determination of billing demand. Each is described in the following discussion.

Demand-Energy Relationship

Approximately 40% of the costs allocated to NP are demand-related in Hydro's forecast cost of service study. Dividing these demand-related costs by appropriate billing determinates yields the full cost-based demand rate. However, there are circumstances where it is desirable to reflect less than the full demand cost in the demand rate charged. The demand cost should be set at a level that:

- Reasonably reflects the cost of deferring new generating capacity on Hydro's system;
- Is sufficient to provide a load management incentive to NP; ***but***
- Is not so high as to encourage NP to add gas turbines for the sole purpose of shaving peak, an action which may not allow Hydro to collect its approved revenue requirement, and may result in non-economic island based resource management.

Also, given a fixed revenue requirement, the level of demand and energy rates varies inversely. In setting an appropriate energy rate Hydro should try to strike a balance between the demand and energy rate levels such that the demand rate satisfies the above criteria with the energy rate reflecting short-run marginal cost, in this case the fuel cost at Holyrood. In order to accomplish this, a two-step energy rate may be appropriate, where the first block is set at, for example, near $0.03 per kWh and the tail block is set at the avoided energy cost.

As customer-related costs represent approximately one percent of NP's cost of service, Hydro may wish to simply include these costs in the energy component of the rate, rather than establish a separate customer component of the rate. The rural deficit portion of Hydro's revenue requirement from NP should continue to be collected in the energy portion of the rate.

Basis for the Determination of Billing Demand

The determination of billing demand is a critical issue in the design of a demand rate to NP. Objectives relevant to Hydro in setting the appropriate billing demand are to:

- Provide an appropriate price signal,
- Ensure a degree of revenue stability,
- Not allow a windfall or loss to either party, and
- Recognize only the relevant variables (i.e., allow for variations in load management and load growth but to normalize for the effects of weather).

NP's monthly billing demand can either be based on 1) their actual monthly demand or 2) keyed off their maximum winter demand.

Using ***monthly billing demands*** offers the advantage of being simple and understandable to the customer. However, the disadvantages include:

- The price signal is not seen as relevant in light of the fact that it is only the winter peak that drives demand costs;
- It may be difficult and impractical to normalize monthly metered demands; and
- This approach has the potential of introducing variations in load in non-winter months due to factors other than weather.

Basing billing demand on the ***single winter peak*** may be seen as punitive from the customer's perspective, but offers as advantages all of the disadvantages in using actual monthly demand. The single winter peak option is therefore seen as the preferred option from Hydro's perspective.

Using the weather normalization procedures discussed in Section 3 and Appendix 1, Hydro would need to normalize NP's actual winter peak. Conceptually, since normalization is used, the only difference between NP's actual peak in the 2004 forecast year and their non-coincident peak in Hydro's operating load forecast for NP should be due to load management and customer growth.

Another consideration in the determination of monthly billing demand is the need to limit Hydro's downside risk. That is, Hydro should not be at risk of not collecting its allowed operating expenses. In addition, Hydro should be reasonably assured of having the opportunity to earn its approved return on equity. One way to accomplish this objective is to base NP's billing demand on its actual weather normalized winter peak, but to set the minimum monthly billing demand at a small nominal value below NP's forecast non-coincident winter demand for the test year. This approach sets a "band" (the difference between the projected demand in the test year load forecast and the minimum billing demand) that will recognize load management efforts by NP in the instant year, and will provide a backstop to Hydro. Hydro and NP should monitor this band to ensure that it continues to serve its intended purpose over time.

Other Ratemaking Techniques

Other than the rate form, ratemaking can also employ other mechanisms to achieve certain objectives. For example, Hydro employs a Rate Stabilization Plan (RSP), which is used to capture changes in energy costs due to changes in fuel price, water availability, and load. The RSP account accumulates the over- or under-collection of revenues and spreads the charge or return of these amounts to the customers over a period of time, thus reducing the impact of short-term and sudden spikes (or valleys) in the underlying costs.

Mechanisms such as the RSP are intended to provide stability in two ways: first in the price to customers, and secondly, through the revenue stream to the utility. The mechanism has other impacts such as keeping the customer or the utility from receiving an immediate economic signal. In ratemaking, special instruments such as the RSP are carefully evaluated and designed to achieve the desired effect and to minimize unwanted impacts.

6.3. Recommended Rate Treatment

This report does not recommend an actual demand rate to NP, but rather, a demand rate structure that is based on the principles set out in this section using the preferred Option A outlined in Section 4. Using these principles, it is recommended that Hydro run cases to carefully determine measures for such things as the appropriate demand/energy balance, variations in its revenue stream, etc. It is also recommended that the results of various cases be shared with NP and that the proposed demand rate be based on discussions between both utilities.

The example provided in Chart 1 is illustrative in form and operation of the type of demand structure that could be appropriate for Hydro. In this example the demand rate is based on NP's full demand cost as determined in the 2004 cost of service study, NP's native load, and the minimum billing demand set at 98% of the 2004 forecast for NP's peak native load less generation credits.

Chart 1
Sample Rate Design Characteristics

Utility

Applicability
This rate is applicable to service to Newfoundland Power

Definitions

“Native Load” means the load supplied by Hydro to Newfoundland Power in any hour, plus the total generation by Newfoundland Power during that hour.

“Minimum Billing Demand” means ninety-eight percent (98%) of Newfoundland Power’s test year Native Load less generation credits.

“Maximum Native Load” means the maximum Native Load of Newfoundland Power in the five-month period beginning in November of the preceding year and ending in March of the current year.

“Weather-Adjusted Native Load” means the Maximum Native Load adjusted to normal weather conditions.

“Weather Adjustment True-up” means one-ninth of the difference between: (a) the greater of the Weather Adjusted Native Load less generation credits, times three and the Minimum Billing Demand; and (b) the sum of the actual billed demands in the months of January, February and March of the current year.

Monthly Charges

Energy*	
First 420,000,000 kWh	$0.0344 / kWh
All Over 420,000,000 kWh	$0.0470 / kWh
Demand	$7.00 / kW of billing demand

Subject to RSP Adjustment

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Determination of Billing Demand

The billing demand in the months of January through March shall be the greater of: (a) the highest Native Load less generation credits beginning in the previous November and ending in the current month; and (b) the Minimum Billing Demand.

The billing demand in the months of April through December shall be the greater of: (a) the Weather-Adjusted Native Load less generation credits, plus the Weather Adjustment True-up; and (b) the Minimum Billing Demand.

7. Recommendations

The preceding sections of this report address what SWMCI considers to be the most relevant issues in implementing a demand-energy rate to NP. Based on our review we find that:

- An energy-only rate to a wholesale customer the size of NP is an anomaly in terms of current industry practice;
- The ability to send a proper price signal to NP is a key element in controlling island interconnected peak and conserving capital costs;
- In order to send a price signal, Hydro must accept a degree of risk and the level of risk that Hydro assumes should be commensurate with the response in terms of conservation efforts by NP;
- A demand-energy rate can be designed that does not permit a windfall to either Hydro or NP due to weather variations;
- A demand-energy rate can be designed that will allow both Hydro and NP to achieve virtually the same operational efficiencies as under the current energy-only rate structure; and
- The rate recommendations discussed in Sections 4 and 6 of this report can effectively address the above concerns.

SWMCI therefore recommends that Hydro perform analyses for the purpose of establishing a demand-energy rate for service to NP using the principles set out in this report. It is also recommended that the results of its analyses be shared with NP and that the proposed rate be based on discussions between both utilities.

Appendix 1 – Weather Normalization

Adjusting Demand for the Effects of Weather

There are several ways of adjusting for weather:

- Use Hydro's load forecast model to derive a weather-adjusted peak, by simulating actual weather conditions at the time of peak.
- Use the weather adjustment model used by NP for energy along with a long-term average load factor to calculate projected peaks and weather-adjusted peaks.
- Agree on the use of one of the preceding methodologies for a period of time while a new equation that evaluates the impact of the weather variables alone is developed.

In using a weather normalization adjustment, there may likely be instances in which the actual metered peak is at or near the test year model predicted peak but the weather adjustment adjusts the measured peak up or down away from the predicted peak.

The following illustrates the use of Hydro's load forecast model and highlights such an instance.

The model equation is driven by several variables including a weather component that is made up of the average temperature over the 20 hours preceding the peak and the average wind speed over the preceding 8 hours. These two weather variables are used to calculate an equivalent wind chill factor, which becomes the weather input to the model. One way to adjust for the weather variation would be to run this model, after the peak has occurred, keeping all variables at the same value except for the weather variable where the normal wind chill variable for the peak day is substituted for the actual wind chill in the model. The result becomes an estimate of the weather-adjusted peak, and the difference between this value and the model predicted value (with actual weather data) is the weather adjustment to be applied.

For example: in the winter of 2000/2001, the model-predicted peak based on actual weather conditions was 1026.9 MW. The actual peak occurred on December 24, 2000 and was 1025.5MW. The temperature variable on the peak day was –5.6 and the wind speed was 47 km/h. This gives a wind chill input variable of –15.6, which is milder than the "normal" of –26.0. Calculating the normalized weather adjusted peak using the model results in a peak of

1085.5 MW. The adjustment is equal to 58.6 MW (1085.5 MW - 1026.9 MW). The 58.6 MW would be added to the actual peak resulting in a weather adjusted actual of 1084 MW.

In the example above, some might question doing an adjustment when the model predicted value and the actual value of peak were so close. However, doing the adjustment removes the weather variation and allows an analysis of what may have caused the growth (or reduction) free of weather impacts. Therefore if the peak (after weather adjustment) is higher than expected it may have been caused by growth. If the weather adjusted peak is lower than expected the cause may have been the impact of LM.

Similar results will occur under any weather-adjustment methodology. The important point is that rates can be designed to send a signal based on a demand that is relatively free of weather impacts.

Appendix 2 –Treatment of NP Generation Credit

This analysis relates to Option C in Section 4.0. Under this option no credit is applied for costing or billing purposes, and NP uses its generation to minimize both its demand and energy cost. The analysis shows the economic impact to NP and the system of operating its generation for the purpose of peak shaving.

In theory this option will provide significant incentive to NP to operate both thermal and hydraulic units so as to minimize their demand and energy that it buys from Hydro. However, NP and the system (society) as a whole could incur additional costs. An analysis has been conducted to determine these savings and costs. This analysis is based on the crucial assumption that NP currently maximizes the energy generated from the hydraulic plants, and changing the treatment of the demand credit would not change the expected amount of energy generated.

From a costing standpoint, the potential advantage to NP would come from reducing its demand by the full amount of generation and in turn reduce the allocated cost. Exhibit 1 shows the maximum benefit NP could receive. It shows the revenue requirement for NP assuming capacity credits of 148MW (no reserve taken out) and compares this to the current methodology. The potential reduction in revenue requirement allocated to NP is $499,400 before the revenue credit and deficit allocation and $421,802 after the revenue credit and deficit allocation.

Under this option there is a potential to incur additional cost on the system because NP would operate its thermal units to reduce peak. This in turn would cause Hydro to reduce generation at Holyrood by an equal amount. Since the NP generation uses a more expensive fuel and is less efficient there would be some additional incremental costs. Exhibit 2 presents the analysis of these costs. The Exhibit shows the analysis under two annual load shapes, (1998 and 2002). The 1998 annual load shape shows a situation where the system peaks were very close to each other in two months thus requiring that NP's generation be run for more hours. This represents a more severe condition. The analysis was also done assuming that the rates were applied based on two different rate designs. The first rate design assumes that the demand charge is based on the annual peak demand. This would cause the NP thermal units to be run only during peak. Under the more severe conditions (system peaks occur in two months) NP's thermal capacity would be expected to run about 12 hours. This mode of operation would result in a cost for fuel to NP of $35,000 and a reduction to Hydro of $15,000. However there would be a net cost to the entire system of $20,000 a very small increase.

If the rate were designed based on actual monthly demand, NP would need to run the thermal units for some time every month to minimize peaks. This analysis also in Exhibit 2 shows an additional cost to NP of $968,000 and a savings to Hydro of $400,000. The net cost to the system would be $568,000.

Most, or all, of this additional cost can be eliminated through operational arrangements between NP and Hydro. Under such an arrangement NP would receive the benefit of the cost being shifted to other classes without incurring any additional costs to the system. However, the cost for Holyrood to generate the equivalent of up 54 MW during peak (fuel cost) would be paid by NP. Depending on rate design (as discussed above) this cost can be as little as $15,000 or as much as $400,000.

This type of transaction would cause a shift in COS cost allocation. The fuel cost that would be shifted to NP reduces the cost to Hydro by an equal amount. This reduction flows through to all the customers. Therefore because of COS allocation ratios, approximately 80% of this reduction would flow through to NP. The bottom line result is that under the best of conditions (all of NP's generation is operable and is used as described above to reduce peak) NP could receive a net benefit roughly in the order of $350,000 to $400,000. NP and its customers, however, would be at significant risk if less than the agreed generation were attained.

Exhibit 1
Newfoundland and Labrador Hydro
2004 Test Year, with NP Generation Credit of 148 MW
Customer Impacts ($ x 1000)

Customer	Increase (Decrease) in Revenue Requirement	
	Before Revenue Credit and Deficit Allocation	After Revenue Credit and Deficit Allocation
Newfoundland Power	(498.4)	(422.6)
Island Industrial	371.2	371.0
Rural Island Interconnected	127.2	--
Rural Labrador Interconnected	--	51.6

Exhibit 2 Page 1 of 2
NP Demand/Energy Rate Analysis
1998 Load Duration Curve Analysis

Scenario 1
NP is subject to a ratcheting Demand Rate and would strive to minimize their Annual Peak Load
NP would use existing thermal capacity to minimize peak.
Assume NP has perfect information.

Unit type	Capacity MW	Operating Hours	Annual Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
Diesel	7.0		13	1,209	583	625
CT	47.2		305	33,950	13,996	19,954
Total	54.2	12	318	35,159	14,579	20,579

Scenario 2
NP is subject to a ratcheting Demand Rate and would strive to minimize their Annual Peak Load
NP would run thermal capacity a total of 200 hours/year (at full capacity)

Unit type	Capacity MW	Operating Hours	Annual Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
Diesel	7.0	200	1,400	133,201	64,277	68,925
CT	47.2	200	9,440	1,051,318	433,409	617,909
Total	54.2	200	10,840	1,184,519	497,686	686,834

Scenario 3
NP is subject to a Monthly Demand Rate and would strive to minimize their Monthly Peak Loads
NP would use existing thermal capacity to minimize peak.
Assume NP has perfect information.

Month	Capacity MW	Operating Hours	Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
January	54.2	9	203	22,348	9,298	13,050
February	54.2	7	194	21,540	8,923	12,618
March	54.2	20	367	40,640	16,840	23,799
April	54.2	15	339	37,662	15,570	22,092
May	54.2	26	640	70,802	29,365	41,436
June	54.2	51	1,077	119,587	49,433	70,153
July	54.2	127	2,203	245,187	101,124	144,063
August	54.2	87	1,447	160,933	66,435	94,498
September	54.2	76	1,420	158,035	65,195	92,840
October	54.2	12	276	30,588	12,654	17,934
November	54.2	13	353	39,159	16,188	22,971
December	54.2	7	193	21,362	8,849	12,513
TOTAL ANNUAL	54.2	450	8,710	967,842	399,875	567,967

Exhibit 2 Page 2 of 2
NP Demand/Energy Rate Analysis
2002 Load Duration Curve Analysis

Scenario 1
NP is subject to a ratcheting Demand Rate and would strive to minimize their Annual Peak Load
NP would use existing thermal capacity to minimize peak.
Assume NP has perfect information.

Unit type	Capacity MW	Operating Hours	Annual Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
Diesel	7.0		19	1,780	859	921
CT	47.2		214	23,787	9,806	13,981
Total	54.2	9	232	25,567	10,665	14,902

Scenario 2
NP is subject to a ratcheting Demand Rate and would strive to minimize their Annual Peak Load
NP would run thermal capacity a total of 200 hours/year (at full capacity)

Unit type	Capacity MW	Operating Hours	Annual Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
Diesel	7.0	200	1,400	133,201	64,277	68,925
CT	47.2	200	9,440	1,051,318	433,409	617,909
Total	54.2	200	10,840	1,184,519	497,686	686,834

Scenario 3
NP is subject to a Monthly Demand Rate and would strive to minimize their Monthly Peak Loads
NP would use existing thermal capacity to minimize peak.
Assume NP has perfect information.

Month	Capacity MW	Operating Hours	Production MWh	NP Prod. Costs 2004$	NLH Avoided HRD Costs 2004$	Net System Costs 2004$
January	54.2	9	232	25,552	10,659	14,893
February	54.2	9	193	21,435	8,879	12,556
March	54.2	46	757	84,145	34,774	49,370
April	54.2	13	321	35,647	14,739	20,908
May	54.2	22	536	59,409	24,623	34,787
June	54.2	5	168	18,595	7,710	10,885
July	54.2	82	1,680	186,693	77,144	109,549
August	54.2	138	2,752	305,783	126,327	179,455
September	54.2	27	550	60,857	25,266	35,592
October	54.2	18	494	54,523	22,695	31,828
November	54.2	19	328	36,386	15,045	21,341
December	54.2	6	165	18,240	7,562	10,678
TOTAL ANNUAL	54.2	394	8,177	907,265	375,421	531,843

Appendix 3 – Comparison of Options

NEWFOUNDLAND AND LABRADOR HYDRO
NP Demand / Energy Rate Analysis
NP Generation Treatment

	Load Forecast		OPTION A Native Load Approach Hydraulic & Thermal Credit		OPTION B Thermal Only Credit		OPTION C No Credit	
	CP	NCP	Costing	Billing Demand	Costing	Billing Demand	Costing	Billing Demand
NP Native Load	1,161.5	1,179.2	1,161.5	1,179.2				
NP Forecast Hydraulic Gen	-77.5	-77.5						
NLH OPLF CP	1,084.0	1,101.7			1,084.0	1,101.7		
NP Forecast Thermal Gen	-45.5	-45.5						
Potential NLH OPLF CP	1,038.5	1,056.2			1,084.0	1,101.7	1,038.5	1,056.2
Demand Credit:								
Hydraulic 94.0 / 1.185			-79.3	-79.3	0.0	0.0	0.0	0.0
Thermal 53.9 / 1.185			-45.5	-45.5	-45.5	0.0	0.0	0.0
			-124.8	-124.8	-45.5	0.0	0.0	0.0
			1,036.7	1,054.4	1,038.5	1,101.7	1,038.5	1,056.2

NOTES:

1. For illustrative purposes, the forecast for NP thermal generation is assumed to match capacity less reserve.
2. If NP's forecast hydraulic generation matched the hydraulic capacity less reserve used in the generation credit calculation, the costing demand would be the same for all three options.
3. NP's generation capacity is being confirmed between NP and Hydro's System Planning department.

Option A:

Costing Demand: NP's native load CP less full credit.

Billing Demand: NP's native load NCP less full credit.

Features:
- Does not require NP's generation to be operated at peak, permitting NP to maximize energy from its hydraulic generation.
- Values the generation credit based on capacity values.

Option B:

Costing Demand: NP's net CP load to NLH, less thermal credit. Net load would only have NP hydraulic generation forecast.

Billing Demand: NP's metered NCP load to NLH. Any thermal generation at time of peak would be added back.

Features:
- Places the economic decision as to how to operate hydraulic generation with NP.
- Values the hydraulic generation credit at what is actually achieved.
- Removes incentive for NP to run more costly thermal generation.
- Increases the chances of a spill and the possibility that hydraulic energy production may not be maximized; instead, it may be operated to shave peak.

Option C:

Costing Demand: NP's net CP load to NLH. Net load would have NP hydraulic and possibly thermal generation forecast.

Billing Demand: NP's metered NCP load to NLH. NP's thermal generation at time of peak would reduce NP's billing demand.

Features:
- Places the economic decision as to how to operate both hydraulic and thermal generation with NP.
- Possibly requires additional operational arrangements if increased overall system costs are to be mitigated.

Constraints: A demand rate should not be so high as to encourage NP to build its own generation.