2006 / 2007

ANNUAL REPORT

April 25, 2008

Management's Discussion and Analysis

The following Discussion and Analysis is abbreviated due to the late production of the Corporation's 2006/07 Financial Statements. These statements were approved by the Board of Directors approximately 9 months later than normal. The Corporation was involved in a rate application which would have a material impact on its 2006/07 financial statements and as a result, the Board agreed to delay the statements until the Regulator reached a Phase I decision, which was received December 31, 2007. Management assumes full responsibility for the information provided in this Discussion and Analysis and confirms that appropriate information systems, procedures and controls are in place to ensure that the information provided is both complete and reliable. These comments should be read in conjunction with the Consolidated Financial Statements included in this report.

Description of the Corporation's Operations

The Northwest Territories Power Corporation (Corporation) is a Crown Corporation of the Government of the Northwest Territories (GNWT) and is a public agency under the *Financial Administration Act*. Under the *Northwest Territories Power Corporation Act*, it is the responsibility of the Corporation to generate, transform, transmit, distribute, deliver, sell and supply energy throughout the Northwest Territories (NWT) on a safe, economic, efficient and reliable basis. The Corporation is regulated by the Northwest Territories Public Utilities Board (PUB).

As the main generator and transmitter of power in the Northwest Territories, NTPC faces many unique challenges to providing safe and reliable electric service. NTPC exists in a unique operating environment. Extremely low customer densities, a harsh climate and logistical challenges, as well as the lack of an integrated transmission system, set the Corporation apart from most utilities. This unique environment has a profound impact on operations throughout the Corporation's service area and is inescapably reflected in the cost to provide service.

NTPC serves a population of approximately 42,700, spread across an area of 1.3 million square kilometres. Seventy five percent of the Corporation's generation mix is from hydro generation – a renewable resource. NTPC supplies hydro power to its wholesale customers, Northland Utilities (YK) Ltd. in Yellowknife and Northland Utilities (NWT) Ltd. in Hay River and area. NTPC provides generation and distribution services to residents in 25 communities – 19 of those communities are served by diesel generation, 2 are served by gas generation priced relative to diesel prices and the remaining 4 communities are served by hydro generation.

While total electrical load is approximately 65 MW, that load is served by an array of discrete systems, ranging from isolated power systems with generating capacity of 240 kW at Colville Lake to the integrated Snare/Yellowknife hydro system with a 65 MW capacity. The Corporation's total installed capacity is over 126 MW. As the Corporation's systems are isolated and unconnected, each must be planned for independently.

The insert map illustrates the operating area of the Corporation, a land area that rivals the largest province in Canada. The detailed map highlights the isolation of many of the communities that we serve – some accessible only by air, barge or winter road. The population is divided among the communities, 25 of which have a population less than 1,000 and only 6 of the 31 communities have more than 1,000 persons, none greater than 20,000.

The Corporation set objectives and strategies in 2006/07 to be efficient and effective while maintaining or improving reliability, delivering quality customer service, operating safely and protecting the environment. In addition, the Corporation continued to work with aboriginal partners to explore hydro development opportunities. The shareholder set the strategic direction which encompassed the core regulated utility business as well as the development of hydro.

OUR VISION

- We will provide environmentally sound, safe, reliable, cost-effective energy and related services in the territories, resulting in recognition as one of the best managed and operated utilities in Canada.

- We will be profitable and financially strong, following sound business practices, and providing an economic return to our shareholder

- We will continue to educate our customers on energy conservation initiatives and work to reduce our own energy by encouraging energy conservation within NTPC.

- We will be a major contributor to the future energy plan for the NWT and partner with communities on local energy plans.

- We will be a major contributor, working with partners, to the development and operation of new energy resources in ways that meet the North's unique environmental needs.

- We will continue to be a full service utility, generating, transforming and distributing power in a maximum number of communities.

- We will be a great place to work – innovative, proactive and driven to meet the expectations of our shareholder, customers and communities.

General Rate Application 2006/08

The Corporation has completed a General Rate Application (GRA) for the 2006/07 and 2007/08 test years and received a final decision from the Public Utilities Board (PUB) on December 31, 2007. A number of factors drove the need to go before the Public Utilities Board (PUB) with an application for the 2006/07 and 2007/08 test years. The Corporation's last rate application was for the test years of 2001/03. It was prepared in 1999. The costs for these test years were forecast using the best information available at the time, however the Corporation was in the process of dividing as a result of the division of the NWT into two territories (NWT and Nunavut) and some costs had no historical benchmarks. Costs associated with regulation and legislation changes since the last GRA (e.g. Safety Bill C-45) were also not reflected in rates.

The Corporation's sales profile changed considerably since the last rate application. In 2001/02, industrial sales represented 14% of total unit sales while in 2005/06 industrial sales were less than 4% of total unit sales. In the future, the industrial customer group will be virtually eliminated as the two gold mines are both in care and maintenance.

Since the last GRA the price of diesel fuel has risen 30 cents a litre or 50% over what was in rates. Gas and purchase power prices are both up to 10 cents over what was in rates, driving increases of 30% and 60% in the fuel component in rates for the communities served by gas. The impact of higher fuel prices will be offset somewhat by an adjustment to the engine efficiencies, which have improved since the last rate application and the improvement in the US/Canadian dollar exchange rate.

The rates set in 2002/03 did not reflect the impact of annual salary increases under the Corporation's collective agreement or the implementation of a new job evaluation system to maintain the Corporation's adherence to equal pay legislation. The Corporation also applied to recover increased pension costs from a change in pension formula which were managed in 2005/06 through a temporary rate rider.

The increase in fuel price affects not only the cost of diesel used to generate power but can be seen through higher transportation and freight costs. A number of other supplies and services costs such as consulting services are also flowing through inflationary increases.

Even without substantial additions increasing amortization, amortization expense is higher in the test years as the true up (amounts being refunded to customers due to over collection in prior years) was completed and the offset to amortization expense in the last rate application will not be repeated. The addition to amortization expense due to the termination of the true up is approximately $1.1 million. In addition capital additions in the intervening years are being amortized.

The general rate application also established the Corporation's allowed return on equity at 8.6% and 9.25% for each of 2006/07 and 2007/08 respectively.

Results of Operations

The Corporation set a number of performance measures for 2006/07, designed to measure differing aspects of corporate performance. Performance targets were set for system reliability, efficiency, safety, human resource retention and financial results.

Performance Measure	**Long Term Target**	**2006/07 Expected Results**	**2006/07Actual Results**	**2007/08 Expected Results**
Debt/Equity	55/45	61/39	59/41	59/41
Plant Efficiency	3.75	3.60	3.54	3.59
Operating Cost per kWh generated	12.00 cents/kWh	14.04 cents/kWh	17.66 cents/kWh	14.04 cents/kWh
Safety – Average lost workdays per 200,000 hrs worked – last 5 years	0	8.21	10.7	7.33
System Availability	99.99%	99.97%	99.98%	99.98%
Staff Turnover	5%	5.0%	7.0%	6.3%

Net income for 2006/07 was $6.4 million, a decrease from 2005/06 of $0.8 million. The Corporation recorded electricity sales of $76.7 million in 2006/07 (not including fuel rider revenue) of which $7.8 million relates to the uncollected shortfall from the approved 2006/07 revenue requirement. The shortfall will be collected through riders and is forecast to be fully collected by December 31, 2008. Other revenues were down from prior year reflecting the end of a temporary rider in 2005/06 which was included in the 2006/07 approved revenue requirement and in future will be included in utility rates. Operating expenses for 2006/07 included a $2.6 million ($4.6 million in 2005/06) fuel expense recorded as an offset to the fuel rider revenue therefore having no impact on net income. Absent that amount operating expenses were up $10.7 million from 2005/06. The increase in expenses relates to a number of adjustments that occur only in a general rate application year such as updates to fuel prices, updates to deferral account annual appropriations and changes in amortization. Other increases relate to inflation as discussed above in the **General Rate Application 2006/08** section of this report

Interest expense was up $1.7 million from the prior year due to lower earnings in sinking funds which are an offset to interest expense. In 2006/07 the portfolio shifted to rely more on fixed income investments in preparation for the retirement of a $20 million sinking fund debentures in March 2009.

Expenditures on hydro development were down $0.1 million from the prior year and account for $0.9 million of the consolidated operating expense in 2005/06. After paying a dividend of $3.5 million to the Shareholder, the Corporation increased retained earnings by $3.0 million.

Financing Activities

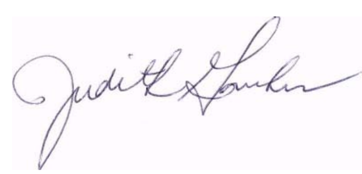
The Corporation did not issue any new long term debt in 2006/07.

Capital Expenditures

Each year the Corporation makes an investment in its capital infrastructure to replace assets that have reached the end of their useful lives. In 2006/07 the Corporation's capital program totaled $14.1 million with the majority of projects aimed at maintaining or improving reliability. The capital identified for 2007/08 continues the trend with most projects in the category of capacity and reliability.

Outlook for 2007/08

An outlook for 2007/08 is not included as the year is now complete and an annual report for 2007/08 will be available soon.



Judith Goucher
Director, Finance & CFO

Auditor General of Canada
Vérificatrice générale du Canada

AUDITOR'S REPORT

To the Minister responsible for the Northwest Territories Power Corporation

I have audited the consolidated balance sheet of the Northwest Territories Power Corporation as at March 31, 2007 and the consolidated statements of earnings and retained earnings, and cash flow for the year then ended. These financial statements are the responsibility of the Corporation's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at March 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles. As required by the *Financial Administration Act* of the Northwest Territories, I report that, in my opinion, these principles have been applied on a basis consistent with that of the preceding year.

Further, in my opinion, proper books of account have been kept by the Corporation and the consolidated financial statements are in agreement therewith. In addition, the transactions of the Corporation that have come to my notice during my audit of the consolidated financial statements have, in all significant respects, been in accordance with Part IX of the *Financial Administration Act* of the Northwest Territories and regulations, *the Northwest Territories Power Corporation Act,* and the by-laws of the Corporation, with the exception that the Corporation did not meet its statutory deadline for submitting its annual report to its Minister as described in the following paragraph.

Section 100 of the *Financial Administration Act* of the Northwest Territories requires the Corporation to submit its annual report to its Minister not later than 90 days after the end of its financial year, or an additional period, not exceeding 60 days, that the Minister of Finance may allow. The Corporation decided to delay the completion of its consolidated financial statements and submitting its annual report to its Minister until Phase 1 of its General Rate Application for the 2006/07 and 2007/08 Test Years was reviewed and approved by the Public Utilities Board of the Northwest Territories on December 31, 2007.

Sheila Fraser

Sheila Fraser, FCA
Auditor General of Canada

Ottawa, Canada
February 29, 2008

NORTHWEST TERRITORIES POWER CORPORATION
CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2007

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements were prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Where GAAP permits alternative accounting methods, management has chosen those it deems most appropriate in the circumstances. The Northwest Territories Power Corporation (the Corporation) is regulated by the Public Utilities Board of the Northwest Territories, which also examines and approves its accounting policies and practices with respect to recovery of assets and expenses. Financial statements include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

The Corporation maintains financial and management systems and practices which are designed to provide reasonable assurance that reliable financial and non-financial information is available on a timely basis, that assets are acquired economically, are used to further the Corporation's aims, are protected from loss or unauthorized use and that the Corporation acts in accordance with the laws of the Northwest Territories and Canada. Management recognizes its responsibility for conducting the Corporation's affairs in accordance with the requirements of applicable laws and sound business principles, and for maintaining standards of conduct that are appropriate to a territorial Crown corporation. An internal auditor reviews the operation of financial and management systems to promote compliance and to identify changing requirements or needed improvements.

The Auditor General of Canada provides an independent, objective audit for the purpose of expressing her opinion on the consolidated financial statements. She also considers whether the transactions that come to her notice in the course of the audit are, in all significant respects, in accordance with the specified legislation.

The Board of Directors appoints certain members to serve on the Audit and Efficiency Committee. This Committee oversees management's responsibilities for financial reporting and reviews and recommends approval of the consolidated financial statements. The internal and external auditors have full and free access to the Audit and Efficiency Committee.

The consolidated financial statements have been approved by the Board of Directors.

Leon Courneya

Leon Courneya, FCA
President & CEO

Judith Goucher

Judith Goucher, MA
Director, Finance & CFO

Hay River, NT
February 29, 2008

NORTHWEST TERRITORIES POWER CORPORATION

Consolidated Statement of Earnings and Retained Earnings
For the year ended March 31
($000's)

	2007	2006
Revenues		
Sale of power	$ 64,115	$ 64,117
GRA shortfall rider (Note 4)	7,795	-
Fuel riders applied against the GRA shortfall (Note 4)	4,759	-
Fuel riders (Note 3)	2,680	4,752
Other (Note 5)	1,339	2,050
	80,688	70,919
Expenses		
Salaries and wages	17,759	16,958
Fuels and lubricants	17,758	11,907
Fuel offset to rider revenue (Note 3)	2,601	4,601
Supplies and services	10,795	9,778
Amortization (Note 6)	12,861	10,357
Travel and accommodation	1,995	1,475
	63,769	55,076
Earnings from operations	16,919	15,843
Insurance proceeds (Note 7)	-	1,410
Insurance expenses (Note 7)	-	(1,410)
	-	-
Interest income	236	335
Earnings before interest expense	17,155	16,178
Interest expense (Note 8)	10,710	8,986
Net earnings	6,445	7,192
Retained earnings at beginning of year (Note 20)	42,633	38,941
Dividend (Note 9)	(3,500)	(3,500)
Retained earnings at end of year	$ 45,578	$ 42,633

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheet
As at March 31
($000's)

	2007	2006
Assets		
Property, plant and equipment (Note 11)		
Plant in service	$ 316,220	$ 304,694
Less accumulated amortization	(83,259)	(76,734)
	232,961	227,960
Construction work in progress	13,352	11,350
	246,313	239,310
Current assets		
Cash	335	2,360
Accounts receivable (Note 10)	17,848	12,670
Inventories	3,464	6,547
Prepaid expenses	507	628
	22,154	22,205
Other long-term assets		
Sinking fund investments (Note 12)	41,681	37,804
Regulatory assets (Note 3)	11,659	12,255
Other	643	462
	53,983	50,521
	$ 322,450	$ 312,036
Liabilities and Shareholder's Equity		
Long-term debt		
Long-term debt, net of sinking fund investments (Note 13)	$ 110,297	$ 115,279
Sinking fund (investments presented as assets)	41,681	37,804
Net lease obligation (Note 14)	1,461	1,481
	153,439	154,564
Current liabilities		
Short-term debt and bank indebtedness (Note 15)	12,800	8,000
Accounts payable and accrued liabilities	16,377	14,522
Dividends payable (Note 9)	3,500	3,500
Current portion of long-term debt (Note 13)	1,105	1,068
	33,782	27,090
Other long-term liabilities		
Regulatory liabilities (Note 3)	34,745	34,249
Asset retirement obligations (Note 16)	4,325	4,215
Environmental liabilities (Note 17)	3,240	3,240
Deferred government contributions (Note 18)	1,775	380
Employee future benefits (Note 19)	2,437	2,536
	46,522	44,620
Shareholder's equity (Note 20)	88,707	85,762
	$ 322,450	$ 312,036
Commitments and contingencies (Note 21)		

The accompanying notes are an integral part of these financial statements.

Approved on behalf of the Board:

Lew Voytilla
Chairman of the Board

Louis Sebert
Director

Consolidated Cash Flow Statement
For the year ended March 31
($000's)

	2007	2006
Cash flows from operating activities		
Cash receipts from customers	$ 70,809	$ 70,796
Cash paid to suppliers and employees	(45,486)	(44,167)
Interest received	236	335
Interest paid	(12,477)	(9,682)
Cash flows from operating activities	13,082	17,282
Cash flows used in investing activities		
Property, plant and equipment constructed or purchased	(16,555)	(22,690)
Proceeds from insurance (Note 7)	2,193	3,961
Cash flows used in investing activities	(14,362)	(18,729)
Cash flows from financing activities		
Proceeds from long-term borrowings	-	15,000
Repayment of long-term debt	(1,067)	(1,032)
Sinking fund instalments	(2,000)	(5,685)
Dividends paid	(3,500)	(3,300)
Net (repayment) / proceeds from short-term borrowings	4,800	(2,000)
Repayment of net lease obligation	(23)	(62)
Government contributions (Note 18)	1,045	730
Cash flows (used in) from financing activities	(745)	3,651
Net (decrease) increase in cash	(2,025)	2,204
Cash at beginning of year	2,360	156
Cash at end of year	$ 335	$ 2,360

The accompanying notes are an integral part of these financial statements.

1. Authority and operation

The NWT Power Corporation (the Corporation, NTPC) is established under the *Northwest Territories Power Corporation Act*. The Corporation is a public agency under Schedule B of the *Financial Administration Act* and is exempt from income tax. The Government of the Northwest Territories (GNWT) owns all of the shares of the Corporation.

The Corporation operates diesel, natural gas and hydroelectric production facilities to provide utility services on a self-sustaining basis in the Northwest Territories.

Consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly owned subsidiaries NWT Energy Corporation Ltd., NWT Energy Corporation (03) Ltd., Sahdae Energy Ltd., and 5383 NWT Ltd.

NWT Energy Corporation Ltd., under the authority of the *Northwest Territories Power Corporation Act*, financed the Dogrib Power Corporation in 1996 for the construction of a 4.3 MW hydro facility. The NWT Energy Corporation (03) Ltd. has three operations: a joint owner (50% shareholder) in Aadrii Ltd., a residual heat project in Fort McPherson, the development of hydro electric business opportunities outside the regulated business and an investment in Dezé Energy Corporation, which is pursuing the development of a hydroelectric project to provide power to the diamond mines. Sahdae Energy Ltd. began operations in 2005. Its mandate is to pursue a hydro development project on the Great Bear River to provide power to the potential Mackenzie Valley pipeline. 5383 NWT Ltd. is inactive.

The Corporation and its subsidiaries account for interests in jointly controlled entities using the proportionate consolidation method. All intercompany transactions and balances have been eliminated upon consolidation.

2. Accounting policies

Rate regulation

The Corporation, with the exception of its subsidiary companies, is regulated by the Public Utilities Board of the Northwest Territories (PUB) pursuant to the *Public Utilities Act*. The PUB regulates matters covering rates, financing, accounting, construction, operation, and service area. As the PUB is a board appointed by the GNWT, and the Corporation is a public agency of the GNWT, the Corporation and the PUB are related parties. Although the PUB and NTPC are related parties, the GNWT can only provide administrative guidance to the PUB and cannot give specific direction to the PUB on a case before them. Therefore, the PUB is independent of NTPC.

The PUB uses cost of service regulation to regulate the Corporation's earnings on a rate of return basis. In the 2006/08 General Rate Application (GRA) the PUB approved an allowed rate of return of 9.284% for 2006/07. As actual operating conditions will vary from forecast, actual returns achieved will differ from approved returns.

The PUB is required by the *Public Utilities Act* to review the affairs, earnings and accounts of the Corporation a minimum of every three years. The regulatory hearing process used to establish or change rates typically begins when the Corporation makes a General Rate Application for its proposed electricity rate changes. Normally, the Corporation applies for rates in advance of the applicable fiscal years (Test Years) to which the new rates will apply. In November 2006, the Corporation filed an application with the PUB for the 2006/07 and 2007/08 Test Years. In addition to General Rate Applications, interim applications may be used between GRAs to deal with circumstances which could result in the use of interim rates or riders until the next rate application when rates are reviewed and set as final.

Revenues

Sale of power, interest, contract and other revenues are recognized on the accrual basis and include an estimate of services provided but not yet billed.

Property, plant and equipment

Property, plant and equipment are recorded at original cost less accumulated amortization and unamortized contributions by utility customers to aid in the construction and acquisition of property, plant and equipment. Costs include materials, direct labour and a proportionate share of directly attributable overhead costs.

Certain regulated additions are made with the assistance of cash contributions from customers when the estimated revenue is less than the cost of providing service. These contributions are amortized on the same basis, and offset the amortization charge of the assets to which they relate. The Corporation retains ownership of these assets.

As a result of using the group method of accounting for amortization, when an asset is retired or disposed of, the retirement of these assets is charged to the accumulated amortization with no gain or losses reflected in operations. Gains or losses arising from exceptional circumstances are included in earnings.

Amortization

Amortization of property, plant and equipment is provided on the straight-line average group useful life basis, at rates which are approved by the PUB, a portion of which is accounted for as a reserve for future removal and site restoration costs. Amortization is suspended when assets are removed from service for an extended period of time.

Included in amortization expense and regulatory liabilities is a reserve for future removal and site restoration. The account will be applied to mitigate the impact of asset dismantling and disposal costs and site restoration costs that are not otherwise related to an asset retirement obligation and environmental liabilities.

Amortization rates are as follows:

	%
Electric power plants	1.16 - 5.25
Transmission and distribution systems	1.09 - 4.66
Electric power plants under capital lease	1.16 - 5.25
Warehouse, equipment, motor vehicles and general facilities	1.76 - 9.76
Other utility assets	2.5 - 20.0
Other	20.0

Inventories

Fuels and lubricants and materials and supplies are valued at weighted average cost. Obsolete inventory is recorded at salvage value in the period when obsolescence is determined.

Sinking fund investments

Securities held in sinking funds are recorded at cost. Interest, dividends and realized gains and losses are included in sinking fund income. Unrealized gains are not recognized. Unrealized losses are recognized only when the decline in value is considered other than a temporary decline in the value of the sinking fund investments.

Public Service Pension Plan

Employees participate in the Public Service Pension Plan (the Plan) administered by the Government of Canada. The Corporation's contributions to the Plan are expressed as a factor of employees' contributions. The factor may fluctuate from year to year depending on the experience of the Plan. The Corporation's contributions are charged to operations on a current basis and represent the total pension obligations. The Corporation is not required to make contributions with respect to actuarial deficiencies of the Plan.

Employee future benefits

Under the terms and conditions of employment, employees may earn non-pension benefits for resignation, retirement and ultimate removal costs based on years of service. The benefits are paid upon resignation, retirement or death of an employee. The cost of these non-pension benefits has been determined based on management's best estimates and accrued as a liability as employees render service. The costs of employee future benefits reflects management's best estimate of costs indexed up for the rate of inflation and discounted using a market interest rate at the end of the year matched to the timing of the benefit payments.

Asset retirement obligations

On an annual basis, the Corporation identifies legal obligations associated with the retirement of its property, plant and equipment. The fair value of the future expenditures required to settle the legal obligations are recognized to the extent that they are reasonably estimable and are calculated based on the estimated future cash flows necessary to discharge the legal obligations and discounted using the Corporation's credit adjusted risk-free rate.

The fair value of the estimated asset retirement obligations are recorded as a liability under other long-term liabilities with an offsetting asset capitalized and included as part of property plant and equipment. The asset retirement obligations are increased annually for the passage of time by calculating accretion (interest) on the liability using the Corporation's credit adjusted risk-free rate. The offsetting capitalized asset retirement costs are amortized over the estimated useful life of the related asset.

The Corporation has identified some asset retirement obligations for its hydro, thermal, transmission and distribution assets. However, since the Corporation expects to maintain and operate these assets indefinitely, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation for these assets cannot be made at this time.

Environmental liabilities

Environmental liabilities consist of the estimated costs related to the management and remediation of environmentally contaminated sites. The Corporation recognizes environmental liabilities when the Corporation is obligated to incur such costs and the costs of remediation can be reasonably estimated. The Corporation reviews its estimates of future environmental liabilities on an on-going basis.

Measurement uncertainty

To prepare these financial statements in accordance with Canadian generally accepted accounting principles (GAAP); management has made a number of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent liabilities and the cost to complete capital projects in progress. Actual results may differ from these estimates. Significant estimates include amortization, employee future benefits, regulatory assets and liabilities, asset retirement obligations and environmental liabilities.

Management's estimates and assumptions regarding regulated assets and liabilities and the timing of the Corporation's ability to recover the cost of these assets through future rates, are subject to decisions of the PUB as described in Note 3.

New accounting recommendations

The Canadian Institute of Chartered Accountants (CICA) issued in January 2005 three new accounting standards that will impact the Corporation. These new standards will come into effect for fiscal years beginning on or after October 1, 2006 and will be applied prospectively.

Section 3855 - *Financial Instruments – Recognition and Measurement*, establishes standards for recognizing, measuring and classifying financial instruments. The Corporation will be required to classify its financial assets as held for trading, held-to-maturity, loans and receivables or available-for sale and financial liabilities as held for trading or other than held or trading. Financial assets and liabilities classified as held for trading will be measured at fair value with gains and losses recognized in net results of operations. Financial assets classified as held-to-maturity, loans and receivables and financial liabilities other than those held for trading will be measured at amortized cost. Financial assets classified as available-for-sale will be measured at fair value with unrealized gains and losses recognized in other comprehensive income.

Section 1530 - *Comprehensive Income*, introduces a new requirement to temporarily present certain gains and losses in other comprehensive income until it is considered appropriate to be recognized in net results of operations. The Corporation may be required to present a new financial statement titled Comprehensive Income to record such amounts until they are realized.

Section 3251 - *Equity* established standards for the presentation of equity and changes in the reporting period.

The Corporation has evaluated the impact of those new recommendations and will be presenting them in its 2007/08 financial statements.

3. Financial statement effects of rate regulation

As a result of rate regulation, the regulatory accounting policies adopted by the Corporation may differ from the accounting policies typically followed by unregulated entities. Specifically, policies in relation to regulatory assets and liabilities and amortization policies are different. A description and summary of the financial statement effects of rate regulation follows. The PUB has approved the accounting treatments described.

Regulatory assets and liabilities

Regulatory assets and liabilities in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the statement of earnings in order to match these expenses and revenues against the amounts collected or refunded through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the PUB renders a subsequent decision.

Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent the Corporation's estimate of future costs to dispose of assets and remediate its sites and the amounts directly paid by customers for assets. These liabilities reduce the future rate impact to customers.

Regulatory assets

	2007	2006	Remaining recovery period
Rate stabilization funds (a)	$ 3,018	$ 4,040	Determined by PUB
Reserve for injuries and damages (a)	2,597	2,579	Determined by PUB
Regulated employee future benefits (a)	1,952	1,884	Determined by PUB
Regulatory costs	1,231	1,232	Determined by PUB
GRA receivable (Note 4)	1,574	-	2 years
Financing costs (a)	967	1,043	26 years
Snare Cascades deferral account (a)	707	1,010	4 years
Water licensing costs	600	-	Determined by PUB
Other regulatory assets	200	765	Determined by PUB
Normalized overhaul costs	(1,187)	(298)	Determined by PUB
	$ 11,659	$ 12,255	

(a) the rate base does not include an allowance for a return on investment.

Rate stabilization funds

The Rate stabilization funds were established by the PUB in 1997/98 through Decision 1-97. The funds mitigate the impact of volatile changes on utility rates from changes in diesel and natural gas fuel prices as well as fluctuations in hydro generation caused by water levels. The impact of any increases or decreases in fuel prices or hydro generation over the PUB approved amounts is deferred. The deferred amounts are accumulated until PUB specified limits are reached and management's judgement deems the recovery (refund) appropriate, at which time rate-riders are applied, with PUB approval, to recover or refund the amounts necessary to bring the funds back to the approved limits. The remaining recovery period is indeterminate as the amounts deferred in the account depend on the market price of fuel and water levels on the Snare and Yellowknife river systems. Traditionally, once the PUB specified trigger limits are reached, the recovery period of the balance of the rate stabilization fund receivable (payable) has been 12 – 24 months.

In the absence of rate regulation, GAAP would require that actual fuel expenses be included in the operating result of the year that they are incurred. In 2006/07, fuel expenses were deferred and consequently lower due to the differences in fuel prices of $870 (2006 - $4,254) and the volume of available water generation of $214 (2006 - $388). The net interest revenues accrued on the balance of the funds also decreased interest expense by $191 (2006 – $157).

There were five fuel stabilization fund rate riders in effect in 2006/07. These riders collected revenues related to fuel expenses deferred in prior years. In 2006/07 these riders collected $7,056 (2006 – $3,837) of which $4,759 (2006 – nil) was reported as fuel riders applied against the 2006/07 GRA shortfall. The remaining amount of the riders collected of $2,297 (2006 - $3,837) was reported as fuel rider revenues with an offsetting and equal charge to fuel expense.

The net effect of rate regulation on net income was an increase of $1,022 (2006 – $962).

Reserve for injuries and damages

The Reserve for injuries and damages includes costs for uninsured and uninsurable losses and the deductible portion of insured claims. The remaining recovery period is indeterminate as the amounts deferred to the account depend on the types and size of emergencies the Corporation faces during a given year. In the 2006/08 GRA, the PUB approved $670 (2006 - $485) to be included in annual expenses for this fund. In 2006/07 actual costs deferred to this account totalled $688 (2006 - $ 1,452). In the absence of rate regulation, GAAP would require that the actual cost of these events be expensed as they occurred. The net effect of rate regulation on net income was an increase of $18 (2006 - $967).

Regulated employee future benefits

Regulated employee future benefits represent benefits accrued under employment agreements since April 1, 2001. The remaining recovery period is indeterminate as the amounts deferred to the account depend on the rate at which hires, retirements, terminations and new employment agreements contribute to Employee Future Benefits (see Note 19). In the absence of rate regulation, GAAP would require that the actual cost of these events be expensed as they occurred. The effect of rate regulation on net income was an increase of $68 (2006 - $430).

Regulatory costs

Regulatory costs include all third party costs and staff overtime, supplies, services and travel the Corporation incurs directly related to General Rate Applications and related regulatory proceedings incurred by the Corporation. In the absence of rate regulation, GAAP would require that the actual regulatory costs be expensed as they were incurred. The remaining recovery period is indeterminate as the amounts deferred to the account depend on the actual regulatory costs the Corporation incurs and this will vary from year to year as regulatory issues arise. In the 2006/08 GRA, the PUB approved $600 (2006 - $228) to be included in annual expenses for this fund. In 2006/07 actual costs deferred to this account totalled $599 (2006 - $339). The net effect of rate regulation on net income was a decrease of $1 (2006 – increase of $111).

Financing cost

The financing cost relating to the issuance of a long-term debt is amortized on a declining balance basis over the 30 year term of the related debt. There are 26 years remaining in the term of the related debt. In the absence of rate regulation, GAAP would require that the financing cost be expensed when incurred. The effect of rate regulation on net income was a decrease of $76 (2006 - $137).

Snare Cascades deferral account

The Snare Cascades deferral account eased the impact on utility rates resulting from the Snare Cascades project being added to the rate base in 1997. The increase in costs caused by the hydro project addition to the rate base, net of savings from displaced diesel generation, was deferred for five years to be amortized over the next ten years to 2011. In the absence of rate regulation, GAAP would require that the actual cost of operations resulting from operating the Snare hydro system with the addition of Snare Cascades be expensed in the year incurred. A portion of the rider is to cover the costs of financing the balance in the fund, therefore the revenues and fuel expense resulting from the implementation of the Snare Cascades rider are not offsetting. In 2006/07, the rider resulting from this fund increased revenues by $383 (2006 - $915) and fuel expense was increased by $304 (2006 - $764). The net effect of rate regulation on net income was an increase of $80 (2006 - $151). The rider rate set to collect the balance in this fund was adjusted early in 2006 to draw the collection term out to 2011.

Water licensing deferral account

The Water licensing deferral account was established in 2006/07 in PUB Decision 13-2007. This account is set up to mitigate the uncertainty around the costs to acquire and maintain water licenses associated with the Taltson hydro plant, Bluefish hydro plant, Snare Cascades hydro plant, Jackfish diesel plant and the Snare Hydro system. In the 2006/08 GRA, the PUB approved $137 (2006 – nil) to be included in annual expenses for this fund. The PUB approved 2006/07 opening balance of $634. This opening balance was transferred into this account from other regulatory assets as well as capital expenditures made in previous years. O&M costs reallocated to this account in 2006/07 totalled ($21) offset by expenditures added to this account that would have otherwise been capital in nature of $123. In the absence of rate regulation, GAAP would require that the cost of these events be expensed or capitalized as they occurred. The effect of rate regulation on net income was a decrease of $116 (2006 – nil).

Other regulatory assets

Other regulatory assets include costs incurred for intangible assets that create a long term benefit to customers. These costs are subject to recovery through the customers through PUB decisions. In the absence of rate regulation, GAAP would require that the actual cost of these events be expensed as they occurred. The remaining recovery period is indeterminate as the amounts deferred to the various accounts depend on what issues arise during the year. The amortization of the various accounts to deferred charges amortization is done on a straight-line basis over periods ranging from 5 to 10 years. Consequently, in the absence of rate regulation, operational expenses would increase by $0 (2006 – $130) and annual amortization expense would decrease by $72 (2006 - $132). The net effect of rate regulation on net income was an increase of $72 (2006 – $2).

Normalized overhaul costs

The Normalized overhaul costs include costs over the life of the assets to overhaul hydro, diesel and natural gas units. In the absence of rate regulation, GAAP would require that the actual overhaul costs be expensed as they were incurred. In the 2006/08 GRA, the PUB approved $1,693 (2006 - $1,573) to be included in annual expenses for this fund. The balance in the account will depend on the frequency and the cost of overhauls and therefore the recovery period is considered to be indeterminate. In 2006/07 actual costs deferred to this account totalled $804 (2006 - $1,049). The net effect of rate regulation on net income was a decrease of $889 (2006 – $524).

L-199 transmission line costs

The L-199 transmission line costs captures the amounts spent to recommission and litigate outstanding issues with respect to the L-199 transmission line. The PUB approved these costs in the 2001/02 General Rate Application. The PUB directed that these costs be set up in a deferral account until such time as the litigation is completed. In 2006, the Corporation received a final settlement on litigation of $1,605. As per PUB Decision 1-2002, in January 2006, the Corporation included the balance of the previously deferred L-199 transmission line costs to its plant, property and equipment for future application to the PUB on the final disposition of this asset. The balance transferred from the deferral account to plant, property and equipment was $3,068 net of litigation proceeds. In the absence of rate regulation, GAAP would require that the amount spent to recommission the line be capitalized and the subsequent recovery of any proceeds from litigation be recorded as revenues at the time they were received. Since all of the transactions regarding this were completed in 2006, the net effect of rate regulation on net income for 2007 was nil (2006 – decrease of $1,376).

Fuel rider revenues

Rider revenues with an associated fuel expense:

	2007		2006	
	Rider revenues	Associated fuel expense	Rider revenues	Associated fuel expense
Rate stabilization funds	$ 2,297	$ 2,297	$ 3,837	$ 3,837
Snare Cascades deferral account	383	304	915	764
	$ 2,680	$ 2,601	$ 4,752	$ 4,601

Regulatory liabilities

	2007	2006	Remaining settlement period
Reserve for Future Removal and Site Restoration *	$ 38,534	$ 37,776	Determined by PUB
Less: Asset retirement obligations	(4,325)	(4,215)	
Environmental liabilities	(3,240)	(3,240)	
	30,969	30,321	
Deferred revenues	3,776	3,928	Determined by PUB
	$ 34,745	$ 34,249	

* During the current year, the Corporation reclassified the asset retirement obligations and environmental liabilities which were previously included in the reserve for future removal and site restoration.

Reserve for future removal and site restoration

The Reserve for future removal and site restoration is a deferral account that records the funds collected from customers for the future removal of assets and the restoration of the Corporation's operating sites that are not otherwise related to an asset retirement obligation or environmental liabilities. This reserve increases annually using PUB approved amortization rates applied over the estimated useful lives of the related assets on a straight-line average group useful life basis. Due to the long term nature of the assumptions made in deriving these estimates, the amortization rates applied are periodically revised and updated for current information. Actual costs incurred in a given year for asset removals and site clean up are charged to this account.

The remaining recovery period is indeterminate due to the amounts added to the fund and the amounts drawing down the balance of the fund each year. The amount by which the fund is drawn down each year depends on which assets are removed from service in that year, the cost of disposal, the site restoration projects undertaken in the year and the costs associated with those projects. The fund is built up each year based on the following rates and the balance in plant, property and equipment of those asset categories:

	%
Electric power plants	0.00 – 2.11
Transmission and distribution systems	0.00 – 1.88
Electric power plants under capital lease	0.00 – 0.26
Warehouse, equipment, motor vehicles and general facilities	(0.74) – 0.35

In a non-regulated industry, future removal and site restoration costs would be limited to asset retirement obligations and environmental liabilities and the removal and site restoration costs would be expensed in the year incurred if they did not relate to an asset retirement obligation or environmental liabilities. In the absence of rate regulation the Corporation's 2006/07 expenses would have been higher by the amount of the removal and site restoration costs deferred in the year of $858 (2006 - $938). Amortization expenses were $1,616 (2006 - $1,561) higher than they would be in the absence of rate regulation. The net effect of rate regulation on net income is a decrease in the amount of $758 (2006 – $623).

Deferred revenues

Deferred revenues reflect contributions to aid in the construction and acquisition of property, plant and equipment. Deferred revenues are amortized on the same basis as the related property, plant and equipment, and the resulting credit is offset against the corresponding provision for amortization of property, plant and equipment (Note 6). In the absence of rate regulation, GAAP would require that the contributions received in a given year be recorded in revenues for that year and amortization expense would not be offset by the amortization of the deferred revenues. The remaining recovery period is indeterminate as the account is increased each year by new contributions received from customers and drawn down by the straight-line amortization of the account balance. The amortization rates for deferred revenues are the same as those found in Note 2 under *Amortization.* In 2006/07, revenues were $245 (2006 - $595) lower than they would have been and amortization on plant, property and equipment was $396 lower (2006 - $381) than it would have been in the absence of rate regulation. The net effect of rate regulation on net income is an increase in the amount of $151 (2006 – decrease of $214).

Capitalized allowance for funds used during construction

The PUB allows the Corporation to capitalize an allowance for funds used during construction (AFUDC) based on the most recent PUB approved cost of capital for the Corporation. The AFUDC rate includes a component for the return on equity. Non-regulated operations would capitalize Interest During Construction (IDC) based on the related cost of debt instead of an AFUDC. Therefore AFUDC as recorded by the Corporation is higher than it would be in a non-regulated operation, as is the subsequent amortization of the capitalized equity component. Capitalized AFUDC is recorded as an offset to interest expense (Note 8). Due to the complexities in the calculation, it is not possible to make a reasonable estimate of the carrying value of the equity component of AFUDC to determine the impact of amortization on net income. In 2006/07, approximately $430 (2006 - $401) was capitalized as the return on equity component of the capitalized AFUDC based on the Corporation's most recent PUB approved cost of capital structure.

The total net effect of rate regulation on net income is as follows:

	2007	2006
Rate stabilization funds	1,022	962
Reserve for injuries and damages	18	967
Regulated employee future benefits	68	430
Regulatory costs	(1)	111
Financing cost	(76)	(137)
Snare Cascades deferral account	80	151
Water licensing costs	(116)	-
Other regulatory assets	72	2
Normalized overhaul costs	(889)	(524)
L-199 transmission line costs	-	(1,376)
Reserve for future removal and site restoration	(758)	(623)
Deferred revenues	151	(214)
Equity component of AFUDC	430	401
Total increase in net income due to rate regulation	$ 1	$ 150

4. Regulatory matters

In November 2006, the Corporation filed Phase I of its General Rate Application with the PUB for the 2006/07 and 2007/08 Test Years requesting, among other things, revenues to recover increased amortization and operating costs associated with increased rate base in the communities served by NTPC. A final decision from the PUB was received on December 31, 2007 and approved a revenue requirement of $76,906 for 2006/07 and $81,389 for 2007/08.

The Corporation filed an application requesting interim refundable rates to recover 75% of the shortfall in 2006/07 pending the PUB's decision on the General Rate Application. Decision 1-2007 approved interim refundable rates. These rates came into effect February 1, 2007 and have collected $1,205 of the $12,554 shortfall through interim rate riders and $4,759 (2006 – nil) (Note 3) by reallocating fuel rider revenues against the 2006/07 GRA shortfall approved by the PUB in Decision 20-2007, leaving a balance receivable of $6,590 as at March 31, 2007. $5,017 of this receivable is due within a year and is included in accounts receivable in Note 10 and $1,574 will be collect after a year and is included as part of regulatory assets in other long term assets in Note 3.

The Corporation intends to file Phase II of its General Rate Application based on the revenue requirement approved in the Phase I Decision. Phase II will set community rates for the 2006/07 and 2007/08 Test Years. It is anticipated that the Phase II Application process will be completed late in 2008.

Given the continued increase in fuel costs over the year, the Corporation applied for an increase to two of the fuel stabilization fund rate riders in November 2006 and received approval for these increases in January 2007.

5. Other revenues

		2007		2006
Contract work	$	447	$	379
Pole rental		266		249
Miscellaneous		244		269
Connection fees		193		185
Heat revenues		141		78
Government assistance (Note 18)		48		145
Pension expenses rider (Note 19)		-		745
	$	1,339	$	2,050

6. Amortization

		2007		2006
Property, plant and equipment	$	10,033	$	8,273
Deferred revenues (Note 3)		(396)		(381)
Regulatory assets and deferred charges		3,224		2,465
	$	12,861	$	10,357

7. Insurance proceeds and expenses

In 2005/06 the Corporation settled three insurance claims, one related to the Ft. McPherson fire from January 2004, one for an engine failure in Inuvik from March 2005 and the third for settlement of a lawsuit related to the rebuilding of the L-199 transmission line on the Snare hydro system. As part of these prior year insurance claims the effect on the Consolidated Income Statement is nil in 2007 (2006 insurance proceeds and expenses of $1,410 each) and the effect on the Consolidated Cash Flow Statement for 2007 is cash received of $2,193 (2006 - $3,961).

8. Interest expense

		2007		2006
Interest on long-term debt	$	13,158	$	12,801
Short-term debt financing costs		451		318
Sinking fund income		(1,878)		(3,269)
Capitalized allowance for funds used during construction		(1,021)		(864)
	$	10,710	$	8,986

9. Dividend

Pursuant to Section 29 of the *Northwest Territories Power Corporation Act*, the GNWT directed the Corporation to declare a dividend of $3,500 (2006 - $3,500).

10. Accounts Receivable

		2007		2006
Utility	$	10,075	$	8,875
GRA receivable (Note 4)		5,017		-
Non-utility		3,091		4,055
Allowance for doubtful accounts		(335)		(260)
	$	17,848	$	12,670

11. Property, plant and equipment

	2007			2006
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Electric power plants	$ 183,202	$ (50,282)	$ 132,920	$ 127,550
Transmission and distribution systems	69,410	(14,492)	54,918	54,913
Electric power plants under capital lease	26,342	(4,323)	22,019	22,423
Warehouse, equipment, motor vehicles and general facilities	24,580	(9,024)	15,556	15,406
Other utility assets	4,228	(1,043)	3,185	3,258
Other	8,458	(4,095)	4,363	4,410
	316,220	(83,259)	232,961	227,960
Construction work in progress	13,352	-	13,352	11,350
	$ 329,572	$ (83,259)	$ 246,313	$ 239,310

Engineering and other direct overhead expenses capitalized during the year amounted to $1,388 (2006 - $1,666).

12. Sinking fund investments

Sinking fund investments are held by the Trustee for the redemption of long-term debt. As the sinking funds exist to fund the payout of long-term debt, sinking fund income is treated as a reduction of finance charges and is reflected in interest expense (Note 8).

The sinking fund agreements require the Corporation to make annual installments to retire debt at maturity. The installments calculated for the next five years are disclosed in Note 13. Fair value information for sinking funds is included in Note 23. The Corporation realized a return of 4.76% (2006 – 10.72%) on the sinking funds.

General Portfolio
Cash and short-term investments include cash and fixed income investments with a term to maturity not exceeding one year. All fixed income securities are investment grade credit. The Corporation's sinking fund policy limits investments in equities to 30% of the total sinking fund market value. Equities can be invested in two funds and are well diversified by sector, issuer, region and liquidity.

Immunized Investments
Between February 2006 and November 2006, the Corporation immunized a portion of the sinking fund investments for the redemption of the March 9, 2009, Sinking Fund Debenture. The assets held in Immunized Investments consist of Federal Government guaranteed securities. The Corporation intends to hold these investments to maturity.

	2007		**2006**	
	Carrying Value	**Weighted average effective rate of return (1)**	**Carrying Value**	**Weighted average effective rate of return (1)**
General Portfolio				
Fixed Income Securities				
Corporate Bonds	$ 10,683	5.26%	$ 8,697	5.35%
Federal Government guaranteed	9,595	4.74%	13,786	4.72%
Municipal Government guaranteed	3,053	5.77%	2,961	5.67%
Provincial Government guaranteed	2,304	4.89%	1,103	5.23%
Cash and short-term investments	1,044	4.40%	46	0.03%
Equities				
Canadian	525		-	
	27,204		26,593	
Immunized Investments				
Federal Government guaranteed	14,477	4.07%	11,211	4.10%
	$ 41,681		$ 37,804	

(1) – Rate calculated on market yield for cash and fixed income securities.

13. Long-term debt

	2007	2006
5.995% redeemable debenture due December 15, 2034	$ 25,000	$ 25,000
11% sinking fund debentures, due March 9, 2009	20,000	20,000
10¾% sinking fund debentures, due May 28, 2012	20,000	20,000
6.63% amortizing debenture, due December 18, 2032	17,333	18,000
11⅛% sinking fund debentures, due June 6, 2011	15,000	15,000
5% redeemable debenture due July 11, 2025	15,000	15,000
6.33% redeemable sinking fund debentures, due October 27, 2018	10,000	10,000
8.41% redeemable sinking fund debentures, due February 27, 2026	8,700	8,700
9.11% debenture series 3, due September 1, 2026, repayable in equal monthly payments of $73.	7,979	8,120
9¾% debenture series 2, due October 1, 2025, repayable in equal monthly payments of $69	7,048	7,177
10% debenture series 1, due May 1, 2025, repayable in equal monthly payments of $70	7,023	7,154
	153,083	154,151
Less: Current portion	1,105	1,068
	151,978	153,083
Less: Sinking fund investments (Note 12)	41,681	37,804
	$ 110,297	$ 115,279

All long-term debt is guaranteed by the GNWT. Fair value information for long term debt is included in Note 23.

Principal repayments and estimated sinking fund investment contributions for the next five years:

	2008	2009	2010	2011	2012
Principal Repayments	1,105	21,153	1,202	1,255	16,311
Sinking Fund Investment Contributions	1,910	1,900	1,900	1,900	1,900

14. Net lease obligation

The NWT Energy Corporation Ltd. loaned funds to the Dogrib Power Corporation to finance the construction of a hydroelectric generating plant on the Snare River in the Northwest Territories from 1994 to 1996. The balance of the loan receivable is $20,545 (2006 - $20,895). The loan bears interest at an annual rate of 9.6%, which is the average rate of interest on NWT Energy Corporation Ltd.'s long-term debt issued to finance the loan. It is due July 2026 and is repayable, in equal monthly payments of $195. The loan is secured by a charge against the plant and the lease agreement.

The Corporation has an initial 65-year lease for the plant at an imputed interest rate of 9.6% from the Dogrib Power Corporation until 2061. The value of the capital lease obligation is $22,029 (2006 - $22,434).

To reflect the effective acquisition and financing nature of the lease, the plant is included in electric power plants in property, plant and equipment at an original cost of $26,342.

Upon consolidation, the loan receivable held by NWT Energy Corporation Ltd. is offset with the capital lease obligation of the Corporation resulting in a net lease obligation of $1,484 (2006 - $1,539). As a result, upon consolidation, in the early years there will be a net payment and in later years there will be a net receipt until such time as the loan receivable is fully repaid in 2026 when only the capital lease obligation payments continue until 2061. The net lease obligation payments / (receipts) over the next five years are:

2008	2009	2010	2011	2012
$ 23	$ (19)	$ (61)	$ (108)	$ (159)

The current portion of the net lease obligation is $23 (2006 - $58) and is recorded in accounts payable. Fair value information for the net lease obligation is included in Note 23.

15. Short–term debt and bank indebtedness

	2007	2006
Shareholder's advance	$ 8,000	$ 8,000
Bank overdraft	4,800	-
	$ 12,800	$ 8,000

The short-term debt outstanding at year-end had a weighted average 68 day term (2006 – 90 day term) and a 4.40% (2006 – 3.61%) weighted average annual interest rate.

The Corporation has a $20,000 unsecured line of credit with its bank, from which $4,800 (2006 – nil) was outstanding at year end. The Corporation also has access on occasion to short term funds from its shareholder.

16. Asset retirement obligations

	2007	2006
Balance, beginning of the year	$ 4,215	$ 4,111
Additions	-	-
Liabilities settled	-	-
Accretion expense	110	104
Balance, end of the year	$ 4,325	$ 4,215

Following is a summary of the key assumptions on which the carrying amount of the asset retirement obligations is based:

- Total undiscounted amount of the discounted cash flows - $7.1 million
- Expected timing of payments of the cash flows – majority of expenditures expected to occur after 2030
- Discount rate – 5.75%

17. Environmental liabilities

The Corporation estimates that it would cost approximately $13,000 to clean-up the environmentally contaminated soil at its 27 sites in the NWT. The Corporation has recognized a provision for environmental liabilities of $3,240 (2006 - $3,240) for the portion of the remediation costs which it believes it is responsible for based on its analysis of the amount of soil impacted before and after the acquisition of the sites by the Corporation on May 5, 1988 from the Northern Canada Power Commission.

18. Deferred government contributions

Capital funding

In 2006, the GNWT agreed to provide the Corporation's subsidiary, the NWT Energy Corporation (03) Ltd. (NTEC03), $1,775 between 2006 and 2007 to study increasing the hydro capacity at the Taltson hydro facility to serve the diamond mines. Under the first contribution agreement, NTEC03 received $730 in funding in 2005/06 to cover $380 of spending on capital projects in 2006 and $350 to provide an advance on the funding for 2007. NTEC03 received the remaining $1,045 in 2007. NTEC03 also signed an agreement with the Federal Government in 2006/07 for $1,000 to study increasing the hydro capacity at the Taltson hydro facility. As a result, $1,000 of the $1,775 received from the GNWT is recorded in accounts payable at March 31, 2007 as NTEC03 has a receivable for this amount as at March 31, 2007 from the Federal Government to cover the same expenditures made during the year.

Other revenues

The Corporation has other agreements with the territorial and federal governments to provide funding assistance to offset costs incurred by the Corporation in its apprenticeship and micro turbine programs. The funding provided under these agreements in 2007 was $48 (2006 - $145) and is included in other revenues (Note 5). These agreements are for the current year.

19. Employee future benefits

The Corporation and all eligible employees contribute to the Public Service Pension Plan (PSPP). This pension plan provides benefits upon retirement based on years of service and the five best consecutive years of earnings. The benefits are fully indexed to the increase in the Consumer Price Index. Prior to 2005/06, the Corporation received funding, recorded as other revenues, from the GNWT to cover part of these pension expenses. As of April 1, 2005 the GNWT ceased its funding of the PSPP. The PUB approved a rate rider to collect $745 for fiscal year 2005/06 to replace funding previously received from the GNWT. The Corporation applied for recovery of this additional expense through rates in the 2006/08 General Rate Application. The Corporation was approved to recover all of this expense through an increase in rates. The Corporation's contributions cover all of the costs associated with the pension obligation.

a) Contributions to the Public Service Pension Plan were as follows:

	2007	2006
Employer's contributions	$ 1,875	$ 1,620
Employees' contributions	839	676
Pension expenses rider	-	(745)
	$ 2,714	$ 1,551

The Corporation provides severance and ultimate removal benefits to its employees based on employee start dates, years of service and final salary. This benefit plan is not pre-funded and thus has no assets, resulting in a plan deficit equal to the accrued benefit obligation.

b) Liability for severance and ultimate removal benefits is as follows:

		2007		2006
Accrued benefit obligation, beginning of the year	$	2,536	$	2,489
Net (decrease) / increase in obligation for the year		(7)		299
Benefits paid during the year		(92)		(252)
Accrued benefit obligation, end of the year	$	2,437	$	2,536

20. Shareholder's equity

		2007		2006
Capital Stock				
Authorized: unlimited number of voting common shares without par value				
Issued: 431,288 common shares	$	43,129	$	43,129
Retained earnings at beginning of year		42,633		38,941
Net earnings		6,445		7,192
Dividends declared		(3,500)		(3,500)
Retained earnings at end of year		45,578		42,633
	$	88,707	$	85,762

21. Commitments and contingencies

Capital projects

The estimated cost to complete capital projects in progress, as at March 31, 2007, was $3,404 (2006 - $8,077).

Natural gas purchase commitment

The Corporation has an agreement to purchase natural gas to produce electricity in Inuvik. The minimum obligation is to purchase 5,622,900m^3 of natural gas per annum until July 2014, consistent with the Corporation's operational requirements. The price is calculated annually on August 1 and will depend on the Edmonton Average Unbranded High Sulphur Diesel Price as posted in the Bloomberg Oil Buyers Guide on that date.

Fuel Management Services Agreement

The Corporation has a fuel management services agreement with the Petroleum Products Division (PPD) of the GNWT. This agreement transfers the fuel inventory and maintenance of fuel tank farms of 20 communities served by the Corporation to PPD, consistent with the Corporation's operational requirements. As of March 31, 2007, all 20 communities had been transferred under this agreement. The price of fuel changes with the amount of fuel purchased by the Corporation from PPD in a given year.

Litigation

The Corporation has been named as a defendant in four lawsuits. One action relates to a wrongful dismissal case, which was raised in 1997/98. The second action names the Corporation as a co-defendant in a lawsuit involving allegations of negligence and breaches of duty arising out of a snowmobile accident. The lawsuit was raised in Nov 2004. In the third action the Corporation is named as a co-defendant in a lawsuit involving allegations of negligence and breaches of duty arising out of a quad accident. The total liquidated amount of these claims ranges from $110 to $459, exclusive of costs and interest. The fourth action was raised in 1996 and names the Corporation as a co-defendant with the GNWT and the Federal Government in a claim for $45,000 related to the construction of the hydro system on the Taltson River in 1965. It is management's estimate that no significant loss to the Corporation will result from any of these four claims. In the event that any of these claims are not settled in favour of the Corporation, the Corporation has insurance which may cover all or a portion of the settlement cost.

Dyke Breach

On June 15, 2006 a breach occurred at a dyke in the Snare Forks hydro system when water over topped the dyke. The breach was closed and remediation work on the channel created has occurred with input from the Department of Fisheries and Oceans. The breach deposited silt into a lake and has impacted fish habitat. The possibility of charges and, if issued, the amount of any penalty are not determinable at this time. Penalties for this type of offence can range from nil to $300,000 per occurrence.

22. Related party transactions

The Corporation is a Territorial public agency and consequently is related to the GNWT and its agencies and corporations.

The Corporation provides utility services to, and purchases fuel and other services from, these related parties. These transactions are at the same rates and terms as those with similar unrelated customers. Transactions with related parties and balances at year-end not disclosed elsewhere in the financial statements are as follows:

	2007	**2006**
Sale of power and other	$ 21,303	$ 20,838
Purchase of fuel from government	8,563	6,463
Other purchases and payments	1,146	736
Fuel tax paid to government	355	486
Balances at year end:		
Accounts receivable	2,306	2,233
Accounts payable	3,959	956
Promissory note (included in short-term debt)	8,000	8,000
Dividend payable	3,500	3,500
Loan repayable to GNWT from NTEC03	1,000	-

23. Financial instruments

	2007			2006		
	Carrying Amount	**Fair Value**	**Term to Maturity**	**Carrying Amount**	**Fair Value**	**Term to Maturity**
Long-term debt	$153,083	$184,643		$154,151	$187,381	
Net lease obligation	1,484	5,355		1,539	4,811	
Fixed Income Securities	25,635	25,492	1 Year to 26 Years	26,547	26,150	1 Year to 42 Years
Cash and Short-Term Investments	1,044	1,044	Less than 1 Year	46	46	Less than 1 Year
Equities	525	541	N/A	-	-	N/A
Immunized Investments	14,477	14,489	Less than 2 Years	11,211	11,247	Less than 3 Years
Fixed-Floating Commodity Swap	-	4,115		-	-	

The fair values of cash, other current accounts receivable and payable and short-term debt approximate the carrying amounts of these instruments due to the short period to maturity.

The fair values for the long-term debt and net lease obligation are determined using market prices for similar instruments.

The fair value of the sinking fund investments is determined using market prices.

On January 18, 2007 the Corporation entered into a fixed-floating commodity swap as the fixed price payer. The commodity is heating oil as quoted on the Nymex exchange, the notional principal is 1,848,000 US gallons and the fixed price is $1.975 CAD/US gallon. The floating price is based on the average heating oil price from July 1, 2007 to September 30, 2007 and the net cash flows will be exchanged on a monthly basis over the three months July 2007, August 2007 and September 2007. As of March 31 2007, the fair value of the contract is $465 higher than the fixed price to be paid by the bank to the Corporation.

24. Segment information

The Corporation has two reportable segments: Regulated operations and Non-regulated operations. Regulated operations include the generation, supply and distribution of energy regulated under the *Public Utilities Act*. Management assesses performance of the regulated operations based on the Corporation's ability to meet targets set out by the Corporation's Board of Directors. These targets cover the following areas: net income, customer service, safety and environmental, financial integrity, employee satisfaction, reliability and operational efficiency.

Non-regulated operations include operations from all of the Corporation's subsidiaries including NWT Energy Corporation Ltd., NWT Energy Corporation (03) Ltd., Sahdae Energy Ltd. and Aadrii Limited. Management assesses performance of the non-regulated operations based the company's ability to achieve its objectives.

	Regulated operations	Non-regulated operations	Total
Year ended March 31, 2007			
Revenues from external sources	80,569	119	80,688
Operating expenses including amortization	62,856	913	63,769
Earnings / (loss) from operations	17,713	(794)	16,919
Interest income	236	-	236
Interest expense	10,590	120	10,710
Net earnings / (loss)	7,359	(914)	6,445
Capital expenditures	15,391	1,504	16,895
As at March 31, 2007			
Total assets	294,450	28,000	322,450

	Regulated operations	Non-regulated operations	Total
Year ended March 31, 2006			
Revenues from external sources	70,915	4	70,919
Operating expenses including amortization	54,050	1,026	55,076
Earnings / (loss) from operations	16,865	(1,022)	15,843
Interest income	335	-	335
Interest expense	8,861	125	8,986
Net earnings / (loss)	8,339	(1,147)	7,192
Capital expenditures	22,095	595	22,690
As at March 31, 2006			
Total assets	285,793	26,243	312,036

25. Subsequent events – NWT Hydro Corporation Act Legislation

In May 2007 the Government of the Northwest Territories enacted the *NWT Hydro Corporation Act.* This legislation creates a new holding company, the Northwest Territories Hydro Corporation (NT Hydro). As a result of the legislation NTPC will become a wholly owned subsidiary of NT Hydro. This legislation also allows for some of the current subsidiaries of NTPC to be moved as directly owned subsidiaries of NT Hydro. The Northwest Territories Hydro Corporation is a public agency of the GNWT. The effective date for the legislation is June 30, 2007.

26. Comparative figures

Certain 2006 figures have been reclassified to conform to the financial statement presentation adopted for 2007.