NTPC 2006/08 GENERAL RATE APPLICATION

GRA Phase I Workshop

January 8, 2007

Outline of Presentation

Section 1 - NTPC's Application

- Background
- Need for Application
- Requested Orders
- Extraordinary Events

Section 2 - Intervenor Issues

- Summary of issues raised
- Each individually addressed

Supporting Materials (as required)

Section 1 - NTPC's Application

Background

- NTPC's last GRA was for the 2001/02 and 2002/03 Test Years
- 2001/03 Phase I GRA was addressed by Negotiated Settlement of all issues.
- No rate changes since that GRA except for specific limited-scope items – fuel, PSSP
- Cost and load pressures have grown throughout NWT. Although this has been mitigated in the intervening years, they have grown to that point that this GRA is needed.
  - Pressures are different and distinct between thermal and hydro communities.

Need for Application – Events since 2001/03

Four major factors are driving the application:

- Fuel Price - 60% increase in cost of diesel (thermal)
- Loss of Customer Credits – Temporary credits in amortization and pension funding no longer exist (primarily hydro, but also some thermal in Inuvik and elsewhere)
- Increased Regulation (Acts) and tight contracting/labour markets (all communities)
- Inflation – overall CPI; 2% - 3% inflation per year (8.2 – 12.6% over 4 yrs) compared to general lack of sales growth. (all communities)

Each of these is addressed in the following material.

Need for Application (2) - Fuel Price

- Fuel prices are driving $5.7 million of the rate increase required in 2006/07 – over 1/3 of the base rate increase.
- In the absence of a GRA, NTPC would recover these costs via fuel riders.
- NTPC's overall fuel volume has gone down dramatically due to Bluefish, Inuvik gas third engine, other load changes (21.5 million litres to 12.6 million) – this has played a major role in mitigating fuel price impacts

Need for Application (3) - Loss of Customer Credits

- As of last GRA, there were almost $2.2 million in “credits” offsetting including $1.4 related to amortization expense (see YK/HR/FS-4).
- These credits have now expired or been cancelled.
- The amortization impact alone comprises 15% of the core shortfall.
- Pressure in future will be upward on amortization – future revisions to amortization rates likely to raise costs (and require “catch up” amortization) rather than additional credits.

Need for Application (4) - regulation and tight contracting / labour markets

- Certain cost areas have increased far ahead of normal inflation,
  - focused primarily on increased regulation, and on the availability and cost of labour and contractors.
- Regulation in the areas of safety, environment, human rights, access to information all impose added workload and training requirements on NTPC.
- Recruiting and retaining skilled workers is extremely difficult in current climate
  - Increases costs and efforts for recruitment
  - Provides rationale for developing own apprentices in-house
- Contracting markets extremely tight – drives high bid contingencies, less responses to tenders. Capital budgeting far more uncertain. Also provides incentive to keep vacancies low.

Need for Application (5) - Inflation compared to lack of sales growth.

- Overall sales are down since the 2002/03 NS levels:
  - thermal community sales are up modestly (3 GW.h,or almost 5%) while hydro is down substantially (12 GW.h or almost 5%)
- Growth in sales for a utility is typically one means to aid in dealing with inflationary pressures on costs
- Absent this growth, there is no way to recover the impacts of inflation except by rate increases.

Need for Application (6) – Other major issues

- NTPC is also dealing with a number of uncertainties at this time:
  - One major area is addressed by proposals in the Application:
    - Water licencing costs have risen and are increasingly hard to predict, and licence durations may be shorter.
  - Two others are left as extraordinary items. NTPC will need to come back to the PUB if these arise.
    - Potential new industrial customers are not expected in the test years, but may arise afterwards.
    - Kyoto could drive new costs or operating regimes that are entirely uncertain at this time.

Requested Orders

1. Revenue Requirement at $79.909 and $84.331 million in 2006/07 and 2007/08:
   - O&M - $31.021 million and $32.484 million for non-fuel expenses in 2006/07 and 2007/08 including:
     - establish fuel prices at the full forecast prices for the respective years, with variances charged to the respective fuel stab funds.
     - increase the annual appropriation to the Reserve for Injuries and Damages from $485,000 per year to $670,000 per year
   - Fuel - $17.154 million and $17.852 million for fuel expenses in 2006/07 and 2007/08
   - Amortization Expenses (net of customer contributions) of $9.588 million and $10.135 million in 2006/07 and 2007/08 respectively for fixed assets

Requested Orders (2)

- Other Amortization of $2.502 million in each test year including:
  - increase the annual appropriation for regulatory hearing costs from the $0.228 million level set at the 2001/03 GRA NS, to $0.600 million
  - adjust the annual cost of overhauls from a level of $1.573 million as set in the 2001/03 GRA Negotiated Settlement to $1.693 million
  - a new water licensing deferral account for all costs including regulatory, compensation, environmental and dam safety studies (excluding capital works) with an annual appropriation of $0.137 million (a normalized 15 year level).
- Return on Rate Base of $20.160 million and $21.788 million in 2006/07 and 2007/08 respectively
  - capital structure of approximately 45% long-term debt, 11% capital lease, -1% no-cost capital and 46% equity in 2006/07, and 42% long-term debt, 11% capital lease, -1% no-cost capital and 49% equity in 2007/08
  - reflecting the results of NTPC's recent review of fair return on equity, at 10.50% for 2006/07 and 10.75% for 2007/08

Requested Orders (3)

2. Approving the forecast 2006/07 and 2007/08 Rate Base at $191.594 million and $201.675 million in 2006/07 and 2007/08 respectively:
   - Bluefish (Capital Project Permit in Decision 12-2002)
     - 2004/05 purchase price (including acquisition costs) of $11.861 million plus $0.742 million in other capital works completed to the end of 2004/05
   - Fort McPherson Power Plant (Decision 6-2004)
     - 2004/05 and 2005/06, to replace the power plant destroyed by fire in 2004 at $7.996 million less insurance proceeds of $5.085 million
   - Snare Rapids Plant Upgrade (Decision 8-2004)
     - As at 2005/06 at $3.838 million and further amounts in 2006/07 to 2007/08 of $1.305 million (for a total $5.143 million)
   - L199 recommissioning (Decision 1-99)
     - previously deferred in the 2001/03 NS pending resolution of the litigation, in 2005/06 at a net cost of $3.068 million
   - Aklavik Power Plant (Decision 11-2006)
     - 2007/08 at $5.298 million

Requested Orders (4)

3. Approving revised **Terms and Conditions of Service** (chapter 7)
4. Approving revised **Maximum Corporate Investment** levels of $1,500 per residence, $750/unit for multiple unit residential dwellings and $250/anticipated kW for General Service customers
5. Approving the **Standby Interconnection Guidelines** and Rate Design Principles
6. **Stabilization Funds**: NTPC is proposing to continue and maintain its fuel and water stabilization funds, all as active funds.
7. **Accounting Provisions:** There are a number of new provisions in Canadian GAAP that could be inconsistent with the way NTPC has maintained its regulatory accounts, as approved by the PUB. NTPC seeks approval and confirmation from the PUB to maintain these funds as per established practice, for the benefit of ratepayers.

Extraordinary Events

- Two possible extraordinary events are highlighted in this GRA that cannot be reasonably forecast today:
  1. Major New Industrial Customers – discussed below in YK/HR/FS-5
  2. Kyoto compliance could result in new costs/operating regimes for NTPC that are uncertain at this time – TGC-17
- This similar to Public Service Superannuation provision from 2001/03 GRA
  - Identified as item beyond NTPC's control; would have to come back to PUB for rider if costs arose in future
  - Ended up getting approval in Decision 6-2005 to put in place rider to collect $745,000 for 2005/06.

Section 2 - Issues Raised by Intervenors

Issues Raised

- YK/HR/FS submitted 12 issues
  - 9 addressed in this presentation
  - 3 best addressed via IR process – items 7, 8 and 12
- TGC submitted 17 issues, plus subparts
  - All addressed in whole or in part in this presentation
  - Some detail requested in subparts best dealt with in IRs

YK/HR/FS-1 – Allocation of costs to rate "zones"

- Phase I GRA does not run COSA – only order of magnitude allocation to thermal versus hydro (not to each community) to help illustrate impacts.
- When budgeting, NTPC's costs are assigned to communities/ zones on the following basis:
  - Community-specific O&M expenses:
    - budgeted directly to community where they are required
  - Area office O&M expenses:
    - budgeted to community where area office is located; allocated via COS
  - Head Office O&M expenses:
    - Budgeted to head office; later allocated via COS process
  - Ops Support O&M expenses:
    - Budgeted to ops support plant; later allocated via COS process
  - Rate Base and Amortization:
    - Assets budgeted/tracked by community
    - Head office rate base is part of head office costs allocate via COS

YK/HR/FS-1 (con't)

- For purposes of Phase I GRA, used hydro/thermal distinction
  - Only intended to be representative; does not run COS
  - NTPC not applying for two separate revenue reqs.
  - Phase I illustrative approach uses 2002/03 COSA ratios for allocating head office and ops support to thermal and hydro.
- Percentages set out in SM-1

YK/HR/FS-2 – Snare Rapids

- Project was approved in Capital Project Permit Decision 8-2004.
  - Budget at that time was $4.984 million – specifically noted as being “budget level”, not “engineering pre-design”
  - Business case was reviewed in Project Permit – risk of loss far exceeds project price
- GRA sets out budget for project at $5.143 million based on updated values at that time.

YK/HR/FS-2 (con't)

- Information on possible changes to annual plant generation has not changed since Project Permit. Key fuel impact is restoring facility and ensuring it can be fully functional to rated capability (as opposed to de-rated condition)
  - Long-term average fuel for GRA retained at 177.5 GW.h for Snare River; assumes full capability of existing system.
- Project budget to end of test years remains valid – however additional amounts after test years (up to $3 million) may be required (e.g., transformers – cost of copper and lack of used market).

YK/HR/FS-3 – Negotiated Settlement

- NTPC views there to be benefits from seeking a negotiated settlement with customers
- Would appear reasonable to put all issues up for negotiation; may be able to address all issues and provide Board with full settlement of all issues – this is best case.
- Would need to target early April period to fit with current schedule.

YK/HR/FS-4 – End of Amortization Credits

- As of the last GRA, two major credits were in place to customers – these are ended in 2006/07:
  - Amortization credit reflecting $1.1 million annually
    - Agreed to in 2001/03 Negotiated Settlement
    - Affects all asset classes and communities, but mostly hydro communities ($0.9 million)
    - Table setting out detail provided in SM-2
  - Inuvik credit from 1983 fire – insurance proceeds amortized over 20 years per NEB (approximately $5.4 million).

YK/HR/FS-5 – New Mining Load

- There is no impact on the test years from “interest from new potential mines”
- Mining operations have approached NTPC regarding regulated service, all remain far from commitment stages to receive grid power;
  - not ready in test years.
- If a new mine were to connect, NTPC would have to come back to PUB for a rate.

YK/HR/FS-6 – Long-Term Wholesale Supply Contracts

- 2001/03 Negotiated Settlement provided that NTPC and its two wholesale customers would enter into negotiations towards a long-term supply agreement for each customer.
- NTPC has pursued discussions with each (without prejudice) but has not been able to negotiate PPA
  - has notified the Board on a number of occasions as to the progress of these discussions.
- NTPC continues to be interested in a PPA to address large wholesale customers, and will continue to work towards such an agreement outside GRA process.
- Any matters relating to long-term supply agreements with either of its wholesale customers are not part of this GRA.

YK/HR/FS-9 - L199 Net Addition

- Copy of letter to Board will be distributed at workshop
- Breakdown of $4.673 million by FERC is provided in Schedule C.2 of GRA
- Total cost of $4.673 million is offset by recovery of $1.605 million as a result of litigation.
- $4.673 million total cost consists of the following:
  - $3.502 million - final project costs
  - $0.758 million - interest on deferral account
  - $0.414 million - legal and court costs
- Details of settlement is confidential

NORTHWEST TERRITORIES POWER CORPORATION

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March 9, 2006

Mr. John Hill
Chairman
Northwest Territories Public Utilities Board
203-62 Woodland Drive
PO Box 4211
Hay River, NT X0E 1G1

Dear Mr. Hill,

Re: Final Disposition of Expenditures for Recommissioning of Transmission Line L199

Pursuant to matters addressed in Board Order 1-1999 and the 2001/03 Phase I Northwest Territories Power Corporation ("NTPC" or "the Corporation") GRA, the Corporation is pleased to notify the NWT Public Utilities Board ("Board") that it has resolved all outstanding legal claims in respect of the capital expenditures for recommissioning transmission line L199.

Background

The L199 transmission line is the main transmission linkage between the City of Yellowknife ("City") and the Snare hydro plants that service the City. NTPC encountered difficulties with this line beginning in 1996/97, as set out in detail in NTPC's L199 Project Permit Application filed with the Public Utilities Board ("PUB") in January 1999 (Decision 1-99). Section 54 of the Act requires NTPC to obtain a Project Permit before undertaking a major capital project.

NTPC applied to the PUB for a project permit to repair the L199 transmission line by letter dated February 9, 1999. The repair related to the "sleeves", which are the joints in the transmission line wire, a number of which failed allowing the L199 line to sag and compromise the safety and reliability of the transmission line. NTPC's application was reviewed by the Board and interested parties, including the City of Yellowknife, through interrogatories. In its letter dated February 11, 1999 responding to the application, the City stated that it "…does not object to the granting of the permit being requested by the Power Corporation" but expressed their interest in ensuring NTPC aggressively pursued legal action against the company that originally constructed the line. At that time, the PUB also reviewed evidence that the project would cost $3.7 million and may increase rates on the Snare-Yellowknife system by an average of 1.8% - 2.2%. In Decision 1-99, the PUB approved NTPC's L199 Project Permit Application. The actual repair costs

incurred by NTPC were $187,000 less than originally forecast and reviewed in Decision 1-99 ($3.7 million - $3.513 million).

On May 9, 2001 NTPC filed its 2001/03 Phase I General Rate Application ("GRA"), which included expenditures associated with the L199 transmission line repairs in its rate base . The expenditures were extensively tested in the pre-hearing proceedings, including two rounds of interrogatories.

The majority of matters addressed in NTPC's 2001/03 Phase I GRA were subsequently resolved by a negotiated settlement among NTPC and interested parties, and approved by the Board in its Decision 1-2002 (the "Negotiated Settlement"). One matter not resolved by the Negotiated Settlement was the costs incurred by NTPC related to repair of the L-199 transmission line. The Negotiated Settlement provides as follows regarding "Treatment of Expenditures in Respect of Transmission Line L199":

> A deferral account will be established to capture the amount expended in respect of the recommissioning of Transmission Line L199 (Project 1015273), and all costs incurred by the Corporation to litigate outstanding issues with respect to Transmission Line L199. Amounts captured by the deferral account will accrue carrying charges calculated in the same manner as carrying charges are calculated for amounts charged to the Corporation's existing stabilization funds. The Board directed the Corporation to apply for approval of the treatment of costs related to Transmission Line L199. Following the final resolution of the existing litigation respecting the Transmission Line L199, the Corporation will apply to the Board to determine the final disposition of the balance in the deferral account. In any proceeding before the Board, to determine the final disposition of balance in the deferral account, interveners are free to take any position they may choose with respect to the disposition of such balance.

Current Status

NTPC has now received final agreements and payment from all parties to the legal claims in respect of the L199 recommissioning. The total recoveries are $1,605,133. In NTPC's opinion, this recovery is reasonable given the circumstances. Considerable time lapsed from when the original line was built, the splice problem detected and the repair affected. None of the NTPC staff who worked on the original construction of the line were still in our employ when the lawsuit commenced. By the end of the end of the discovery process none of the staff who worked directly on the repair were still employed by the Corporation. The original project involved contractors, subcontractors and manufacturers of the sleeve dies, some of whom were no longer in business or in financial difficulty when the lawsuit commenced. NTPC aggressively pursued recourse against all parties through legal avenues, involving a significant time commitment from the President & CEO. A mediator was employed to reach a settlement with the parties.

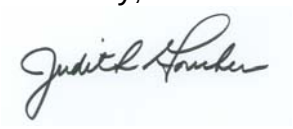
Starting in January 2006, with the receipt of recoveries from the parties to the lawsuit, the Corporation has added the asset to its Capital Plant in Service and terminated the deferral account treatment. This is consistent with normal accounting for assets that are

used, useful and in service, and with the resolution of the legal claims there is no further basis for retaining the deferral account. This treatment will ensure no further interest accrues on the deferral account balance after December 31, 2005.

As NTPC is now actively preparing its next General Rate Application, the Corporation is not now applying to the PUB for any changes to its rates to reflect the addition of the transmission line to ratebase. This matter is best addressed as a component of future hearings on a General Rate Application.

This notification is being copied to all Snare-Yellowknife zone interveners in NTPC's 2001/03 GRA proceeding. Should the Board have any questions, please contact me at 867-874-5234.

Sincerely,



Judith Goucher
Director of Finance and CFO

cc. Interested Parties

YK / HR / FS-10 – Debt Costs

- Schedules similar to Schedule 3.2.5 from the 2001/03 GRA are provided in SM-3

YK / HR / FS-11 – Capital Lease

- Tables calculating the capital lease obligation effective interest rate are provided in SM-4

TGC-1 – Head Office Costs

- Head Office cost breakdown provided in SM-5
- Allocation addressed in YK-1
- Further detail best addressed in IRs.

TGC-2 – Budgeting Process

- NTPC prepares annual budgets for O&M and capital, and long-term budgets for capital.
- Annual budgets were reviewed by BOD in March 2006:
  - did not include many “special GRA” topics, like changes to deferred costs, amortization
  - Also sought further review of some specific items
- Items reviewed or updated between March and November filing were load forecast (uses August 2006), special GRA topics, and some capital spending.

TGC-3 – Diesel Fuel Purchasing

- **Fuel Price** – largest change is agreement with PPD.
  - NTPC secures benefits of larger shipping volumes, PPD take care of storage, inventory, maintenance.
  - prices remain at level available to large purchaser
  - Guarantees access to fuel from same provider dealing with most of NWT (PPD)
- **Purchased power agreements** – have only one (with IOL for Norman Wells)
  - Purchase Power Price = opportunity cost of diesel fuel to produce electricity if NTPC were to do so at its power generating facility.
  - The fuel price equals the ESSO Edmonton Rack price for Regular Sulphur Diesel and is adjusted quarterly.
  - Benefits for NTPC in terms of O&M, staffing, transportation, carrying costs

TGC-3 (con't)

- Hedging – no hedges in place today
  - Hedging is a difficult issue for a regulated utility – has been used in past, but cautiously
  - Fuel stab. funds serve to stabilize prices for cust.
  - Potential to enter into hedge – may reduce 2007/08 summer resupply fuel prices from what is in GRA, but hard to predict if customers will be better off "locking in" now or paying going price this summer.
  - Also issue of accounting – very complicated for hedging instruments
  - Purpose is not to "win", but to mitigate risk – like insurance. Alternative to doing nothing, which is a form of speculation.

TGC-4 - Inflation

Inflation for Budgeting

- NTPC budgets based on forecast costs, as set out in TGC-2
- The 2006/07 rev. req. based on NTPC budget values
- For 2007/08, NTPC makes use of inflation assumptions to escalate costs compared to 2006/07:
  - 3% for labour inflation
  - 2% for all costs except travel
  - 3% for travel-related costs
  - 0% for amortized costs
- 2007/08 estimates also reflect known cost changes, such as changes to staffing

TGC-4 (con't)

Inflation for Benchmarking

- In helping present the rate impacts and justification for cost increases since 2002/03, NTPC makes use of inflation values for Yellowknife (smaller communities not tracked by Stats)
  - The inflation levels are discussed in Chapter 1 page 1-3.
- Annual Yellowknife inflation for the 4 years since 2002/03 was 2.9%, 2.4%, 1.4% and 2.3% (average of 2.3%).
- However, transportation category is higher than average, so expect CPI for smaller communities to be higher than Yellowknife.
- Also salary escalation recently is above average CPI

TGC-5 – Closure of YK mines

- Mine load has decreased substantially since last GRA
  - From 34.7 GW.h in 2002/03 to 8.3 in 2007/08, a drop of 26.4 GW.h
  - Revenue decrease at existing rates is approximately $3.6 million/year
- All direct impacts are isolated to Yellowknife area
- Indirectly, have no material impact on Head Office cost allocation to thermal communities and Taltson area
  - Head Office and Ops Support costs are allocated two ways, “labour” and “customer”.
    - Customer – no impact – still 2 industrial customers
    - Labour – no impact – has resulted in some reduction in staff at Jackfish, but this is offset by staff at Bluefish

TGC-6 – Pension Expense

- NTPC employees are members of the Public Service Pension Plan administered by the Government of Canada as required by legislation.
- NTPC's contributions are expressed as a percentage of the employees' contributions. Cost is lower than running own pension plan.
- NTPC contributions are charged to operations on a current basis and represent the total pension obligations
  - NTPC is not required to make contributions with respect to actuarial deficiencies of the Plan.
- All employees other than casual are required to be members
- Data on contributions is best answered in IR process to the extent relevant.

TGC-7 – Contractor vs. In-house Labour "Proposal"

- NTPC has not made any form of new proposal related to contracting out.
- Key focus on page 1-5 referenced need to keep vacancies low, as contractor "backfill" difficult to secure (or secure cost effectively).
- This is part of rationale for apprenticeships.
- Any proposals to increase contracting out would also be constrained by collective agreement provisions
- Issue of line trades arises for both staff and contractors.

TGC-8 – Opening Balances

- Question raises issue of 2006/07 opening balances, and the extent they reflect actual results.
- NTPC can confirm 2006/07 opening balances reflect actual results for 2005/06.

TGC-9 – Misc. Revenues

- Miscellaneous revenues consist of items such as:
  - Pole rentals
  - Connection charges
  - Contract work
  - Building and equipment rentals
  - Connect and disconnect charges
- Miscellaneous revenues are tracked by community where relevant (e.g., pole rentals, heat revenues).
- Revenues that are not community-specific are not allocated to communities until Phase II – last time allocation was based on labour ratios.
- Table setting out detail provided in SM-6

TGC-10 – Sales Forecast

- NTPC's methodology was updated and reviewed in detail in 2001/03 (chapter 10 and App. A10)
  - Focuses on regression from observed data, adjusted for known factors.
- Same methodology is in use today. 2006/07 forecasts reflect experience with 2005/06 actuals.
- For the thermal communities overall in 2006/07 compared to 2002/03 Negotiated Settlement:
  - General Service usage is nearly identical to 2002/03 due to limited average growth (27.98 MW.h/customer versus 27.92) and customer #s are almost flat (1,500 vs. 1,412)
  - Residential usage is up per customer (6.09 MW.h/customer versus 5.53) while numbers are down (4,675 versus 5,006)
  - Comprises many small changes - extensive detail in App. A.

TGC-11 – Bluefish Capacity

- Purchase of Bluefish added 7 MW of capacity
- The Snare-Yellowknife RFC criteria were approved by the PUB in 14-2004. It involves a two-part criterion each of which must be independently met.
  - The first requires the system LOLE to be less than 2.0 hours/year
  - The second requires that Yellowknife have sufficient generation to meet the non-industrial peak plus 5% with the Snare transmission line L199 out of service.
- In the test years, the system meets the LOLE criteria, but fails the N-1 criteria by less than 1 MW in 2006/07 and less than 2 MW in 2007/08. Without Bluefish, neither would be met (by a substantial amount).
- NTPC is not proposing test year projects to address this shortfall

TGC-11 (con't)

- NTPC plans to address the coming Snare-Yk shortfalls as part of planning for retirement of the 2 Mirrlees KV16 units at Jackfish.
  - These units are each 5.15 MW, are now over 30 years old and are approaching end of life.
- Under current planning scenarios, likely install 12-14 MW of diesel units (or equivalent) in Jackfish in 2009/10 (potentially in the form of 4.5 MW units) with the first Mirrlees retirement.
- After installation of 12-14 MW of diesel units in 2009/10, the system will meet both N-1 and LOLE criteria through approximately 2013/14 (assuming modest system growth of about 2% and no new industrial loads)
- The second Mirrlees unit is currently expected to be retired about 2013/14. By replacing this second unit with two 4.5 MW diesels, the system is expected to meet both criteria through 2019/20.

TGC-11 (con't)

- In the test years, NTPC has surplus hydro on Snare-Yellowknife
  - about 30 GW.h in 2006/07 and 26 GW.h in 2007/08
- Despite this, purchase of Bluefish is net positive in 2006/07 and 2007/08 due to energy contribution
- In 2006/07, Bluefish is helping avoid approximately 13.3 GW.h of diesel or $2.8 million in fuel costs. In 2007/08 this is 16.5 GW.h or $4.0 million
  - will grow in future once the full 42.5 GW.h output is needed in Yellowknife.
- The cost for Bluefish are as follows:
  - In 2006/07 O&M is $0.7 million, amortization $0.26 million, return is $1.4 million, for a total $2.4 million
  - In 2007/08 O&M is $0.7 million, amortization $0.35 million, return is $1.8 million, for a total $2.9 million
- Rev. req. benefit - $0.4 million in 2006/07 and $1.1 million in 2007/08.
- Bluefish is also adding useful capacity (peaking output) to the system.
- Purchase of Bluefish is not expected to have any effect on Thermal communities in Phase II.

TGC-12 – Change in GAAP

- GRA does not reflect any changes due to adoption of new accounting standards.
- New GAAP has been adopted by NTPC in various areas, but none to date has had any quantitative impact on revenue requirements.
- There is potential in future that, without clarity from PUB, certain sections now in place will cause issues for rate setting – NTPC has asked for these to be addressed by PUB at pages 3-20 to 3-24. Three items are noted there:
  - Deferral Accounts - overhauls, water licencing, rate case and injuries and damages
  - Asset Retirement Obligations – keep reserve for removal and restoration status quo, rather than take into equity
  - Financial Instruments – continue to record only realized gains and losses on sinking funds, and not unrealized

TGC-13 – Plant Additions

- All plant additions over $100,000 are set out in Appendix C by community
- Project justification is set out in write-up. Most projects required for capacity, reliability, safety, etc.
- Very few are based on “savings” (NPV) – largest exception is Inuvik 3rd gas engine
- CIAC details set out in SM-7

TGC-14 – Environmental / Remediation Costs

- Phase I, II or III assessments have been prepared in all communities.
- Compiled volumes and estimated remediation costs (2005$) provided in SM-8
- Spending in the test years is approximately $0.6 million per year, charged to Reserve for Restoration
- Spending focused on Fort McPherson, Yellowknife, Tuktoyaktuk, Fort Resolution, Aklavik, and Lutsel K’e.

TGC-15 – Engine Overhauls

- Dealt with in GRA at Section 6.2, item 17 – Community-specific table in SM-9
- Deferred “normalized” overhaul account part of 2001/03 NS.
- Designed to capture average expenses over the long-term. In some communities, overhauls are rare; long-term averages can arise over more than a decade.
- At NS, estimates developed for each community – knew would have to true some up based on experience.
- Only three communities have fallen behind the NS estimates – NTPC proposes to increase these three (shown compared to revenues at existing rates in parenthesis):
  - Fort Liard – proposed to be raised by $0.035 million (3.4%)
  - Nahanni Butte – raised by $0.015 million (4.1%)
  - Fort Good Hope –raised by $0.02 million (1.2%)

TGC-16 – Non-utility Operations

- NTPC has very limited non-utility operations. Subsidiaries or operations to:
  - Finance Snare-Cascades with the Dogrib Power Corp – no change to treatment from previous GRAs
  - District heating in Fort McPherson – no change to accounting treatment
  - New hydro business development – only real change in last 5 years. No costs included in GRA
- Non-regulated operations have very limited assets (feasibility studies, some heating assets) and staff.
- There is no competitive related parties requiring "code of conduct" as seen in other jurisdictions
- All budgeting for NTPC regulated operations excludes costs related to non-regulated subs.

TGC-17 – Efficiency Gains

i. Demand Side Management initiatives:

- Detail at page 8 of Executive Summary
  - Residential Energy Audits in all communities
  - General Service Energy Audits for 5 customers
  - Streetlight changeouts
  - Information packages on household energy consumption and conservation tips on bills.
  - GS demand charge public information
  - Work with GNWT Energy Coordinating Committee and Arctic Energy Alliance

TGC-17 (con't)

ii. Fuel Efficiencies

- Question is misleading - cites average fuel efficiency increasing from 3.575 kW.h/litre in 2002/03 NS to 3.587 in 2006/07.
  - Thermal communities has increased from 3.503 (on 43.3 GW.h generation) to 3.596 (on 42.6 GW.h) an increase of 2.6% (and higher than any year of actuals recorded since last GRA)
  - Hydro communities have dropped from 3.673 (on 33.8 GW.h) to 3.458 (on 2.6 GW.h) – reduction is clearly driven by change in use of diesels
- NTPC's action on addressing fuel cost pressures are addressed in Executive Summary pg. 6
- In future, engine and fuel environmental requirements may lead to downward pressure on fuel efficiencies.

TGC-17 (con't)

iii. Line Losses

- Overall line losses corporate-wide remain at 5.7% of generation
- Thermal communities:
  - at basically the same level as 2002/03 forecast totals (7.2%) but are up from NS values used for setting rev. req. (6.3%), as NS had some community losses artificially "capped" at 7% of generation
    - These losses are now confirmed by over a decade of experience – they are not anomalies – are included in rev. req.

TGC-17 (con't)

iii. Line Losses (con't)

- Hydro:
  - Losses are at 5.2% compared to 5.5% approved in 2002/03 NS
  - Snare down materially at 3.4% compared to 5.2%. Reflects largely reduced loads on system.
  - Taltson at 10.2% is down from 2002/03 (11.2%, however NS reflected "capped" amount at 6.7%) – not particularly relevant as all losses served by surplus hydro

TGC-17 (con't)

iv. Station Service

- Corporate wide station service loads down by 1 GW.h since 2002/03 NS (despite adding new plant at Bluefish and electric heating at Jackfish).
- Diesel community station service down from 3.5 GW.h to 3.3 GW.h (over 5%)
- Reflects more efficient variable speed drives, lighting.
- A certain amount of fixed station service is required regardless of the load.

TGC-17 (con't)

v. Reducing dependence and vi. Alternative generation

- In most thermal communities, few practical alternatives to diesel fuel
- NTPC proposed mechanism to enhance investigation of alternative energy in last GRA – rejected by intervenors
- Inuvik and Norman Wells have focused on maximizing natural gas, including new 3rd gas engine in Inuvik
- Working with GNWT on energy plan
- Wind monitoring in Yellowknife
- Participated with GNWT in study of gasification of communities along the MV pipeline route
- NTPC does not qualify for a lot of gov't funding – does help customers access funding for alternative energy, such as streetlight changeouts and solar generation pilot.
- Investigating hydro options for Wha Ti (with community and INAC)
- Potential for submersible hydro turbines in Fort Simpson

TGC-17 (con't)

vii. Kyoto targets

- The Corporation has reduced its greenhouse gas emissions to 44% below 1990 levels.
  - Construction of Snare Cascades
  - Improved engine efficiency
  - Streetlight conversion projects
  - Gas engines in Inuvik
  - Purchase of Bluefish Hydro
  - Closure of gold mines in Yellowknife
- This is far better performance than required by Kyoto.
- At this point there is no knowledge of what Canada might need to do to meet Kyoto – cannot forecast costs or implications for NTPC. Continue to try to assess.
- This is maintained as one of two extraordinary risks and events that is not addressed by forecasts costs in GRA.
- Working with CEA on issue

TGC-17 (con't)

viii. Streetlighting efficiencies

- Since 2002/03 worked with 11 communities to complete streetlight changeouts
- 3 additional communities will have streetlights converted in 2006/07. Norman Wells only thermal community not yet converted.
- Total streetlighting load reduced from 1.8 GW.h to 1.5 GW.h since last GRA – a reduction of 15%
- Also helped customers access government funding for the capital costs – help offset rate impact.

TGC-17 (con't)

ix. Community involvement

- Regional Directors meet with community leaders at least twice per year
- Occasionally Line crews meet with SAO's when in community for maintenance work
- Regular community letters are sent updating leaders/councils on operations
- Specific community involvement on large capital projects (Ft. McPherson re-build, new Aklavik plant, Inuvik gas engine). In some cases involves meetings on community requirements, project options, costs.
  - Example of Inuvik –provided letter of support for the third engine project.

TGC-17 (con't)

x. and xi. Local hires

- NTPC has an Employment Equity Policy to proactively seek to find and train employees local to NWT.
- Also within GNWT Affirmative Action policy.
- All 5 line apprentices hired are eligible under the Affirmative Action policies.
- 90 individuals working for the Corporation (over half the employees) are affirmative action employees. This does not even include all northern hires.

Supporting Material

SM-1 – YK / HR / FS-1 Rate Zone Allocation Table

Northwest Territories Power Corporation
2006/07 - 2007/08 General Rate Application
2002/03 Ph I "Illustrative" Allocation of Head Office

Plant No.		Head Office Total
	Hydro Total	**39.8%**
	Thermal Total	**60.2%**

SM-2 – YK / HR / FS-4 Amort. Credits

Northwest Territories Power Corporation
2006/07 - 2007/08 General Rate Application
Schedule of Amortization Expense Credits in place in 2002/03 Test Year Ending by 2006/07 Test Year ($000s)

Plant No.	Community	Amortization Reserve Variance	Inuvik Insurance Proceeds Amortization
101	Yellowknife	-641	
104	Wha Ti	-10	
105	Gameti	-22	
108	Behchoko	0	
109	Dettah	1	
110	Lutsel K'e	-2	
201	Fort Smith	-247	
203	Fort Resolution	-2	
205	Fort Simpson	-18	
206	Fort Liard	-6	
207	Wrigley	-6	
208	Nahanni Butte	-3	
209	Jean Marie River	-1	
301	Inuvik	-95	-263
304	Norman Wells	-7	
305	Tuktoyaktuk	-65	
306	Fort McPherson	1	
307	Aklavik	-8	
308	Deline	-23	
309	Fort Good Hope	-21	
310	Tulita	-16	
311	Paulatuk	-25	
312	Sachs Harbour	-12	
313	Tsiigehtchic	-9	
314	Colville Lake	-2	
315	Ulukhaktok	-1	
901	Head Office	132	
		-1,107	**-263**

SM-3 – YK / HR / FS-10 Debt cost

NORTHWEST TERRITORIES POWER CORPORATION

EFFECTIVE COST OF LONG TERM DEBT
2004/05 Actual
(in thousands of dollars)

Line No.											
1	Loan #	2	3	4	6	7	10	11			TOTAL
2	Loan Amount	$ 20,000	$ 15,000	$ 20,000	$ 8,700	$ 10,000	$ 20,000	$ 25,000	TOTAL	(Less)	NET OF
3	Interest Rate	11.000%	11.125%	10.750%	8.41%	6.330%	6.420%	5.955%	ALL	SINKING	SINKING
4	Issue Date	9/Mar/89	6/Jun/91	28/May/92	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	LOANS	FUNDS	FUNDS
5	From Beginning of Year	1/Apr/04	1/Apr/04	1/Apr/04	1/Apr/04	1/Apr/04	1/Apr/04	1/Apr/04			
6	To	9/Mar/05	6/Jun/04	28/May/04	27/Feb/05	27/Oct/04	18/Dec/04	15/Dec/04			
7	Number of Days	342	66	57	332	209	261	258			
8	From	9/Mar/05	6/Jun/04	28/May/04	27/Feb/05	27/Oct/04	18/Dec/04	15/Dec/04			
9	To	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05			
10	Number of Days	23	299	308	33	156	104	107			
11	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	19,333	-	93,033	24,082	
12	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	18,667	25,000	117,367	28,850	
13	**Weighted Average Balance [(L11*(L7/365))+(L12*(L10/365))]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**19,143**	**7,329**	**100,172**		
	DEBT FINANCING COSTS										
14	Beginning Financing Costs O/S	38	68	58	44	79	1391	0	1678		
15	Additions							188	188		
16	Less Amortization	8	9	9	3	5	49	3	86		
17	Ending Financing Costs O/S	30	58	49	41	74	1343	185	1779		
18	**Average Financing Costs Outstanding [(L19+L22)/2]**	**34**	**63**	**53**	**43**	**76**	**1,367**	**92**	**1,729**		
19	**AVERAGE PROCEEDS [L13-L21]**	**19,966**	**14,937**	**19,947**	**8,657**	**9,924**	**17,776**	**7,236**	**98,443**	**26,466**	**71,978**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
20	Interest Expense Amount [L13*L3]	2,200	1,669	2,150	732	633	1,241	435	9,060		
21	Amortization of Finance Costs	8	9	9	3	5	49	3	86		
22	**Total Interest and Amortization**	**2,208**	**1,678**	**2,159**	**734**	**638**	**1,290**	**438**	**9,146**	**1,354**	**7,792**
23	**EFFECTIVE COST OF LONG TERM DEBT [L22/L19]**										**10.826%**

SM-3 (con't)

NORTHWEST TERRITORIES POWER CORPORATION

EFFECTIVE COST OF LONG TERM DEBT
2005/06 Actual
(in thousands of dollars)

Line No.		2	3	4	6	7	10	11	12	TOTAL ALL LOANS	(Less) SINKING FUNDS	TOTAL NET SINKING FUNDS
1	Loan #											
2	Loan Amount	$ 20,000	$ 15,000	$ 20,000	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000			
3	Interest Rate	11.000%	11.125%	10.750%	8.41%	6.330%	6.420%	5.955%	5.000%			
4	Issue Date	9/Mar/89	6/Jun/91	28/May/92	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05			
5	From Beginning of Year	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05	1/Apr/05			
6	To	9/Mar/06	6/Jun/05	28/May/05	27/Feb/06	27/Oct/05	18/Dec/05	15/Dec/05	16/Dec/05			
7	Number of Days	342	66	57	332	209	261	258	259			
8	From	9/Mar/06	6/Jun/05	28/May/05	27/Feb/06	27/Oct/05	18/Dec/05	15/Dec/05	16/Dec/05			
9	To	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06			
10	Number of Days	23	299	308	33	156	104	107	106			
11	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	18,667	25,000	-	117,367	28,850	
12	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	18,000	25,000	15,000	131,700	37,804	
13	**Weighted Average Balance [(L11*(L7/365))+(L12*(L10/365))]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**18,477**	**25,000**	**4,356**	**121,533**		
	DEBT FINANCING COSTS											
14	Beginning Financing Costs O/S	30	58	49	41	74	1343	185	110	1,890		
15	Additions											
16	Less Amortization	8	9	9	3	5	143	6	2	185		
17	Ending Financing Costs O/S	22	49	40	39	68	1200	178	109	1704		
18	**Average Financing Costs Outstanding [(L19+L22)/2]**	**26**	**53**	**44**	**40**	**71**	**1,271**	**181**	**110**	**1,797**		
19	**AVERAGE PROCEEDS [L13-L17-L23]**	**19,974**	**14,947**	**19,956**	**8,660**	**9,929**	**17,206**	**24,819**	**4,247**	**119,736**	**33,327**	**86,409**
	INTEREST & AMORTIZATION OF FINANCING COSTS											
20	Interest Expense Amount [L13*L3]	2,200	1,669	2,150	732	633	1,198	1,489	216	10,286		
21	Amortization of Finance Costs	8	9	9	3	5	143	6	2	185		
22	**Total Interest and Amortization**	**2,208**	**1,678**	**2,159**	**734**	**638**	**1,341**	**1,495**	**217**	**10,472**	**3,145**	**7,326**
23	**EFFECTIVE COST OF LONG TERM DEBT [L22/L19]**											**8.479%**

SM-3 (con't)

NORTHWEST TERRITORIES POWER CORPORATION

EFFECTIVE COST OF LONG TERM DEBT
2006/07 Forecast
(in thousands of dollars)

Line No.												
1	Loan #	2	3	4	6	7	10	11	12			TOTAL
2	Loan Amount	$ 20,000	$ 15,000	$ 20,000	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000	TOTAL	(Less)	NET
3	Interest Rate	11.000%	11.125%	10.750%	8.41%	6.330%	6.420%	5.955%	5.000%	ALL	SINKING	SINKING
4	Issue Date	9/Mar/89	6/Jun/91	28/May/92	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05	LOANS	FUNDS	FUNDS
5	From Beginning of Year	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06	1/Apr/06			
6	To	9/Mar/07	6/Jun/06	28/May/06	27/Feb/07	27/Oct/06	18/Dec/06	15/Dec/06	16/Dec/06			
7	Number of Days	342	66	57	332	209	261	258	259			
8	From	9/Mar/07	6/Jun/06	28/May/06	27/Feb/07	27/Oct/06	18/Dec/06	15/Dec/06	16/Dec/06			
9	To	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07			
10	Number of Days	23	299	308	33	156	104	107	106			
11	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	18,000	25,000	15,000	131,700	37,804	
12	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	17,333	25,000	15,000	131,033	42,440	
13	**Weighted Average Balance [(L11*(L7/365))+(L12*(L10/365))]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**17,810**	**25,000**	**15,000**	**131,510**		
	DEBT FINANCING COSTS											
14	Beginning Financing Costs O/S	22	49	40	39	68	1200	178	109	1,704		
15	Additions											
16	Less Amortization	8	9	9	3	5	80	6	6	126		
17	Ending Financing Costs O/S	15	39	31	36	63	1119	172	103	1578		
18	**Average Financing Costs Outstanding [(L19+L22)/2]**	**19**	**44**	**35**	**37**	**66**	**1,159**	**175**	**106**	**1,641**		
19	**AVERAGE PROCEEDS [L13-L17-L23]**	**19,981**	**14,956**	**19,965**	**8,663**	**9,934**	**16,651**	**24,825**	**14,894**	**129,869**	**40,122**	**89,746**
	INTEREST & AMORTIZATION OF FINANCING COSTS											
20	Interest Expense Amount [L13*L3]	2,200	1,669	2,150	732	633	1,156	1,489	750	10,778		
21	Amortization of Finance Costs	8	9	9	3	5	80	6	6	126		
22	**Total Interest and Amortization**	**2,208**	**1,678**	**2,159**	**734**	**638**	**1,236**	**1,495**	**756**	**10,904**	**1,452**	**9,452**
23	**EFFECTIVE COST OF LONG TERM DEBT [L22/L19]**											**10.532%**

SM-3 (con't)

NORTHWEST TERRITORIES POWER CORPORATION

EFFECTIVE COST OF LONG TERM DEBT
2007/08 Forecast
(in thousands of dollars)

Line No.		2	3	4	6	7	10	11	12	TOTAL	(Less)	TOTAL NET
1	Loan #											
2	Loan Amount	$ 20,000	$ 15,000	$ 20,000	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000	ALL	SINKING	SINKING
3	Interest Rate	11.000%	11.125%	10.750%	8.41%	6.330%	6.420%	5.955%	5.000%	LOANS	FUNDS	FUNDS
4	Issue Date	9/Mar/89	6/Jun/91	28/May/92	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05			
5	From Beginning of Year	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07	1/Apr/07			
6	To	9/Mar/08	6/Jun/07	28/May/07	27/Feb/08	27/Oct/07	18/Dec/07	15/Dec/07	16/Dec/07			
7	Number of Days	343	66	57	332	209	261	258	259			
8	From	9/Mar/08	6/Jun/07	28/May/07	27/Feb/08	27/Oct/07	18/Dec/07	15/Dec/07	16/Dec/07			
9	To	31/Mar/08	31/Mar/08	31/Mar/08	31/Mar/08	31/Mar/08	31/Mar/08	31/Mar/08	31/Mar/08			
10	Number of Days	22	299	308	33	156	104	107	106			
11	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	17,333	25,000	15,000	131,033	42,440	
12	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	16,667	25,000	15,000	130,367	47,276	
13	**Weighted Average Balance [(L11*(L7/365))+(L12*(L10/365))]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**17,143**	**25,000**	**15,000**	**130,843**		
	DEBT FINANCING COSTS											
14	Beginning Financing Costs O/S	15	39	31	36	63	1119	172	103	1,578		
15	Additions											
16	Less Amortization	8	9	9	3	5	78	6	6	124		
17	Ending Financing Costs O/S	7	30	22	33	57	1042	166	98	1454		
18	**Average Financing Costs Outstanding [(L19+L22)/2]**	**11**	**35**	**26**	**34**	**60**	**1,080**	**169**	**101**	**1,516**		
19	**AVERAGE PROCEEDS [L13-L17-L23]**	**19,989**	**14,965**	**19,974**	**8,666**	**9,940**	**16,063**	**24,831**	**14,899**	**129,327**	**44,858**	**84,469**
	INTEREST & AMORTIZATION OF FINANCING COSTS											
20	Interest Expense Amount [L13*L3]	2,200	1,669	2,150	732	633	1,133	1,489	750	10,755		
21	Amortization of Finance Costs	8	9	9	3	5	78	6	6	124		
22	Total Interest and Amortization	**2,208**	**1,678**	**2,159**	**734**	**638**	**1,210**	**1,495**	**756**	**10,879**	**1,649**	**9,230**
23	**EFFECTIVE COST OF LONG TERM DEBT [L22/L19]**											**10.927%**

SM-4 – YK / HR / FS-11 Capital Lease interest rate

2007/08	Avg. Rate Base	21,843,204
	Avg. % Equity	6.74%
	Avg. Equity	1,471,955
	Equity Rate	10.50%
	Avg. % Debt	93.26%
	Avg. Debt	20,371,249
	Weighted Debt Rate	9.63%
	Mid-year cost rate	9.70%

SM-5 – Head Office Costs

NORTHWEST TERRITORIES POWER CORPORATION
2006/07 - 2007/08 GENERAL RATE APPLICATION
REVENUE REQUIREMENT BY GENERATION TYPE ($000s)

Line No.		2006/07 Forecast			2007/08 Forecast		
		Hydro	Thermal	Total	Hydro	Thermal	Total
1	**Plant Non-Fuel Operation & Maintenance Expense**						
2	Salaries and Wages	$ 5,669	$ 7,343	$ 13,012	$ 6,040	$ 8,008	$ 14,048
3	Non-Production Fuel and Lubricants	247	484	730	252	494	745
4	Supplies and Services	4,693	4,070	8,763	4,776	4,148	8,923
5	Travel and Accommodation	664	1,002	1,665	684	1,032	1,715
6	**Total Plant Non-Production Fuel Operation & Maintenance Expense for GRA**	**11,272**	**12,898**	**24,170**	**11,750**	**13,681**	**25,432**
7	**Head Office Non-Fuel Operation & Maintenance Expense**						
8	Salaries and Wages	$ 1,734	$ 2,624	$ 4,358	$ 1,792	$ 2,712	$ 4,504
9	Supplies and Services	846	1,280	2,126	862	1,305	2,168
10	Travel and Accommodation	187	283	470	193	291	484
11	**Total Head Office Non-Production Fuel Operation & Maintenance Expense**	**2,767**	**4,187**	**6,954**	**2,847**	**4,308**	**7,155**
12	Less: Corporate Donations	32	71	103	32	71	103
13	**Total Non-Production Fuel Operation & Maintenance Expense for GRA**	**14,007**	**17,014**	**31,021**	**14,565**	**17,918**	**32,484**
14	**Production Fuel Expense**						
15	Fuel	515	14,253	14,767	430	14,830	15,259
16	Purchased Power	-	2,387	2,387	-	2,593	2,593
17	**Total Production Fuel Expense**	**515**	**16,639**	**17,154**	**430**	**17,422**	**17,852**
18	*Less Hydro Communities Fuel Expense Captured in Water Stabilization Funds*	*515*		**515**	*430*		**430**
19	**Amortization**						
20	Fixed Asset Amortization (less Customer Contributions)	5,576	4,011	9,588	5,756	4,378	10,135
21	Amortization of Deferred Charges	1,037	1,465	2,502	1,037	1,465	2,502
22	**Total Amortization Expense**	**6,613**	**5,476**	**12,089**	**6,794**	**5,843**	**12,637**
23	**Total Return on Rate Base**	**13,937**	**6,223**	**20,160**	**14,574**	**7,214**	**21,788**
24	**Total Revenue Requirement**	**$ 34,557**	**$ 45,353**	**$ 79,909**	**$ 35,933**	**$ 48,398**	**$ 84,331**

SM-6 – TGC-9 Misc. Revenues

Northwest Territories Power Corporation
Miscellaneous Revenues
2006/2007
Thousands of Dollars

Plant No.	Community	Connection Charges	Contract Work	Resid. Heat Recovery	Build & Equip. Rentals	User Pay Fees	Misc Income	Pole Rental Income	Total
101	Yellowknife		20					2	22
104	Wha Ti							5	5
105	Gameti							5	5
108	Behchoko							16	16
109	Dettah							2	2
110	Lutsel K'e							7	7
201	Fort Smith		75		4			34	112
203	Fort Resolution							6	6
205	Fort Simpson							33	33
206	Fort Liard							6	6
207	Wrigley							5	5
208	Nahanni Butte							2	2
209	Jean Marie River							2	2
301	Inuvik		75	40				40	155
304	Norman Wells							23	23
305	Tuktoyaktuk						72	13	85
306	Fort McPherson							12	12
307	Aklavik							12	12
308	Deline							7	7
309	Fort Good Hope							5	5
310	Tultia							6	6
311	Paulatuk							4	4
312	Sachs Harbour							2	2
313	Tsiigehtchic							5	5
314	Colville Lake							1	1
315	Ulukhaktok							6	6
	Community Wide Total		170	40	4		72	260	546
901	Head Office	160				100	33		293
	Grand Total	160	170	40	4	100	105	260	839

SM-6 (con't)

Northwest Territories Power Corporation
Miscellaneous Revenues
2007/08
Thousands of Dollars

Plant No.	Community	Connection Charges	Contract Work	Resid. Heat Recovery	Build & Equip. Rentals	User Pay Fees	Misc Income	Pole Rental Income	Total
101	Yellowknife		20					2	22
104	Wha Ti							5	5
105	Gameti							5	5
108	Behchoko							16	16
109	Dettah							2	2
110	Lutsel K'e							7	7
201	Fort Smith		75	20	4			34	132
203	Fort Resolution							6	6
205	Fort Simpson							33	33
206	Fort Liard							6	6
207	Wrigley							5	5
208	Nahanni Butte							2	2
209	Jean Marie River							2	2
301	Inuvik		75	40				40	155
304	Norman Wells							23	23
305	Tuktoyaktuk							13	13
306	Fort McPherson							12	12
307	Aklavik							12	12
308	Deline							7	7
309	Fort Good Hope							5	5
310	Tultia							6	6
311	Paulatuk							4	4
312	Sachs Harbour							2	2
313	Tsiigehtchic							5	5
314	Colville Lake							1	1
315	Ulukhaktok							6	6
	Community Wide Total		170	60	4			260	494
901	Head Office	160				100	33		293
	Grand Total	160	170	60	4	100	33	260	787

SM-7 Customer Contributions

Northwest Territories Power Corporation
2006/07 - 2007/08 General Rate Application
Schedule of Customer Contributions by Plant ($000s)

	2006/07					2007/08				
Plant No.	Gross Customer Contributions	Opening Accumulated Amortization	Amortization Expense	Closing Accumulated Amortization	Mid-Year Net Customer Contributions	Gross Customer Contributions	Opening Accumulated Amortization	Amortization Expense	Closing Accumulated Amortization	Mid-Year Net Customer Contributions
101	815	-492	-38	-531	303	815	-531	-38	-569	265
104	461	-433	-20	-453	18	461	-453	-20	-473	-2
105	239	-116	-11	-127	117	239	-127	-11	-138	106
108	145	-53	-6	-59	88	145	-59	-6	-66	82
109	68	-29	-3	-32	37	68	-32	-3	-35	34
110	243	-129	-10	-139	109	243	-139	-10	-148	99
201	219	-67	-9	-75	148	219	-75	-9	-84	140
203	56	-19	-3	-21	36	56	-21	-3	-24	33
205	228	-110	-10	-119	113	228	-119	-10	-129	104
206	379	-224	-16	-240	147	379	-240	-16	-256	131
207	130	-124	15	-109	13	130	-109	15	-94	28
208	82	-78	-3	-81	2	82	-81	-3	-84	-1
209	131	-112	-5	-118	16	131	-118	-5	-123	10
301	1,674	-571	-57	-628	1,075	1,674	-628	-57	-686	1,018
304	354	-162	-14	-176	185	354	-176	-14	-190	171
305	497	-468	-21	-489	18	497	-489	-21	-509	-2
306	215	-120	-7	-127	91	215	-127	-7	-135	84
307	428	-231	-18	-249	188	428	-249	-18	-267	170
308	378	-226	-15	-240	145	378	-240	-15	-255	131
309	413	-233	-17	-250	171	413	-250	-17	-267	154
310	309	-264	-13	-276	38	309	-276	-13	-289	26
311	438	-327	-19	-346	101	438	-346	-19	-365	82
312	192	-170	-7	-177	18	192	-177	-7	-185	10
313	119	-73	-3	-77	44	119	-77	-3	-80	41
314	526	-289	-18	-307	228	526	-307	-18	-325	210
315	457	-384	-20	-403	64	457	-403	-20	-423	44
	9,194	**-5,505**	**-347**	**-5,852**	**3,515**	**9,194**	**-5,852**	**-347**	**-6,199**	**3,168**

SM-8 Soil Remediation Costs

Northwest Territories Power Corporation
Compilation of Impacted Soil Volumes and Remediation Costs

	Soil Volumes m^3	Remediation Cost ($000s) (2005$)
Aklavik	3519	508
Colville Lake	748	194
Deline	4140	538
Fort Good Hope	5750	748
Fort Liard	3450	621
Fort McPherson	3450	621
Fort Resolution	1754	456
Fort Simpson	3450	449
Fort Smith	863	224
Ulukhaktok	920	239
Inuvik	19953	2099
Jean Marie River	6095	927
Lutsel K'e	978	254
Nahanni Butte	575	150
Norman Wells	2415	435
Paulatuk	0	0
Behchoko	1639	426
Gameti	6613	917
Sachs Harbour	5750	854
Tsiigehtchic	1553	280
Tuktoyaktuk	1093	284
Tulita	0	0
Wha Ti	7820	929
Wrigley	4140	538
Yellowknife	1495	269
Total	88159	12959

SM-9 – TGC-15 Overhauls

NWT POWER CORPORATION
DEFERRED OVERHAUL ACCOUNT CONTINUITY SCHEDULE
2001/02 to 2003/04

Plant no.	Community	2001/02 Actual Spending	2001/02 Normalized Provision	2001/02 Account Balance	2002/03 Actual Spending	2002/03 Normalized Provision	2002/03 Account Balance	2003/04 Actual Spending	2003/04 Normalized Provision	2003/04 Account Balance
101	Yellowknife	243	394	(151)	373	416	(194)	837	416	227
104	Wha Ti	143	35	108		35	73	6	35	44
105	Gameti	18	20	(2)	30	20	8	24	20	12
108	Behchoko		10	(10)		10	(20)		10	(30)
110	Lutsel K'e		20	(20)	6	20	(34)	16	20	(38)
201	Fort Smith	126	105	21	185	117	88	56	117	27
203	Fort Resolution		10	(10)		10	(20)		10	(30)
205	Fort Simpson	133	100	33	4	100	(63)	202	100	39
206	Fort Liard	12	35	(23)	11	35	(46)	72	35	(9)
207	Wrigley	20	15	5	(2)	15	(12)	10	15	(17)
208	Nahanni Butte	6	10	(4)		10	(14)	9	10	(15)
209	Jean Marie River	13	10	3	1	10	(6)		10	(16)
301	Inuvik	270	380	(110)	466	380	(24)	225	380	(179)
304	Norman Wells		10	(10)		10	(20)		10	(30)
305	Tuktoyaktuk	4	60	(56)	29	60	(86)	36	60	(110)
306	Fort McPherson	23	45	(22)	13	45	(53)	5	45	(93)
307	Aklavik	6	45	(39)	152	45	68	41	45	64
308	Deline	37	40	(3)	27	40	(16)	18	40	(38)
309	Fort Good Hope	24	40	(16)	88	40	32	32	40	25
310	Tultia	2	35	(33)	6	35	(63)	9	35	(89)
311	Paulatuk	1	30	(29)	32	30	(28)	10	30	(48)
312	Sachs Harbour	1	30	(29)	2	30	(57)		30	(87)
313	Tsiigehtchic	20	15	5	15	15	5		15	(10)
314	Colville Lake		10	(10)	1	10	(19)		10	(29)
315	Ulukhaktok	7	35	(28)	9	35	(54)	51	35	(38)
	CORPORATE TOTAL	**1110**	**1540**	**(430)**	**1449**	**1573**	**(554)**	**1659**	**1573**	**(468)**

SM-9 (con't)

NWT POWER CORPORATION
DEFERRED OVERHAUL ACCOUNT CONTINUITY SCHEDULE
2004/05 to 2005/06

Plant no.	Community	2004/05 Actual Spending	2004/05 Normalized Provision	2004/05 Account Balance	2005/06 Actual Spending	2005/06 Normalized Provision	2005/06 Account Balance
101	Yellowknife	888	416	698	144	416	426
104	Wha Ti	22	35	31	10	35	6
105	Gameti	39	20	31	22	20	33
108	Behchoko		10	(40)		10	(50)
110	Lutsel K'e	34	20	(24)		20	(44)
201	Fort Smith	47	117	(43)	26	117	(135)
203	Fort Resolution	3	10	(37)		10	(47)
205	Fort Simpson	11	100	(50)	18	100	(132)
206	Fort Liard	78	35	33	51	35	49
207	Wrigley	2	15	(30)	13	15	(31)
208	Nahanni Butte	18	10	(7)	1	10	(17)
209	Jean Marie River	8	10	(18)	12	10	(16)
301	Inuvik	536	380	(23)	395	380	(8)
304	Norman Wells		10	(40)		10	(50)
305	Tuktoyaktuk	191	60	20	103	60	63
306	Fort McPherson	50	45	(88)	36	45	(96)
307	Aklavik	54	45	74	16	45	45
308	Deline	(3)	40	(82)	17	40	(105)
309	Fort Good Hope	134	40	119	127	40	205
310	Tultia	70	35	(54)	15	35	(74)
311	Paulatuk	11	30	(67)		30	(97)
312	Sachs Harbour	8	30	(109)	3	30	(136)
313	Tsiigehtchic	12	15	(14)		15	(28)
314	Colville Lake	()	10	(39)	5	10	(44)
315	Ulukhaktok	55	35	(18)	38	35	(15)
	CORPORATE TOTAL	**2268**	**1573**	**226**	**1050**	**1573**	**(297)**

SM-9 (con't)

NWT POWER CORPORATION
DEFERRED OVERHAUL ACCOUNT CONTINUITY SCHEDULE
2006/07 to 2007/08

Plant no.	Community	2006/07 Forecast Spending	2006/07 Normalized Provision	2006/07 Account Balance	2007/08 Forecast Spending	2007/08 Normalized Provision	2007/08 Account Balance
101	Yellowknife	251	461	216	444	461	198
104	Wha Ti	55	35	25	49	35	39
105	Gameti	20	20	33	15	20	28
108	Behchoko		10	(60)		10	(70)
110	Lutsel K'e	24	20	(40)	90	20	30
201	Fort Smith	81	117	(171)	82	117	(206)
203	Fort Resolution		10	(57)		10	(67)
205	Fort Simpson	146	100	(86)	213	100	27
206	Fort Liard	35	75	9	144	75	78
207	Wrigley	21	15	(25)	24	15	(16)
208	Nahanni Butte	76	25	35	13	25	23
209	Jean Marie River	40	10	14	8	10	12
301	Inuvik	98	380	(291)	290	380	(381)
304	Norman Wells		10	(60)		10	(70)
305	Tuktoyaktuk	126	60	130		60	70
306	Fort McPherson	78	45	(64)	70	45	(39)
307	Aklavik		45			45	(45)
308	Deline	22	40	(123)	24	40	(139)
309	Fort Good Hope	88	60	234	250	60	424
310	Tultia	43	35	(66)	137	35	36
311	Paulatuk	9	30	(118)		30	(148)
312	Sachs Harbour	25	30	(141)	20	30	(151)
313	Tsiigehtchic	35	15	(8)	14	15	(9)
314	Colville Lake		10	(54)		10	(64)
315	Ulukhaktok	56	35	6	15	35	(14)
	CORPORATE TOTAL	**1328**	**1693**	**(663)**	**1902**	**1693**	**(454)**