

1 **EXECUTIVE SUMMARY**

2 **Background**

3 The Northwest Territories Power Corporation (“the Corporation” or “NTPC”) adjusted rates in
4 January 2008 to implement rate increases approved by the NWT PUB for the 2007/08 test
5 year. These rate adjustments collect NTPC’s approved revenue requirement on a forward
6 looking basis. Ordinarily a Phase II application, such as the one prepared by the Corporation
7 for the 2001/02 and 2002/03 General Rate Application, would follow the approval of the
8 Corporation’s Phase I Application and revenue requirement. A Phase II General Rate
9 Application (GRA) addresses cost-of-service methods and proposals for rate rebalancing
10 between customer classes and communities. However, following the approval of its Phase I
11 GRA, and considering the longstanding 15% cap on rate increases, set by the PUB and
12 continued in this Application, the Corporation has several outstanding issues related to costs
13 and revenues following the 2006/07 and 2007/08 Phase I Application:

14

- 15 1. There is approximately **\$8.383 million** in outstanding revenue shortfalls related to the
16 2006/07 and 2007/08 year revenue requirements approved by the PUB that need to
17 be collected. These amounts relate to costs already incurred to provide service to
18 customers.
- 19 2. There are substantial balances in the fuel stabilization funds that need to be
20 collected, approximately **\$5.393 million** in the diesel communities; Inuvik; Norman
21 Wells; Yellowknife and Fort Smith fuel stabilization funds. These amounts relate to
22 costs already incurred to provide service to customers.

1 3. For the first time since its inception, the Snare/Yellowknife water stabilization fund is
2 outside of its approved operating range, with approximately **\$1.654** million in
3 collections required to return the fund to within its operating range. These amounts
4 related to costs that have already been incurred to provide service to customers.

5 4. Fuel prices have increased substantially – 60 per cent - since the Corporation filed
6 the Phase I Application in November, 2006. Approximately **\$5.778 million** annually is
7 required to keep up with these fuel price increases.

8
9 Currently there are rate riders in place to address some of these costs that collect
10 approximately \$3.385 million annually. In total, the Corporation is requesting approval to
11 implement rate riders that will increase revenues by approximately \$12.7 million annually, or
12 approximately 15%. The impact on Residential customers who are eligible for the Territorial
13 Power Support Program (TPSP) and use 700 kW.h per month is estimated at approximately
14 \$12 per month. Table 1 provides a summary of the revenue increases that are being
15 requested in this application. Table 2 summarizes the total requested increases per kW.h,
16 considering base rates, stabilization fund riders and shortfall riders.

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Table 1. 2006/07 and 2007/08 Shortfall Rider and Stabilization Fund Rider Finalization Impacts

3

	18 month catch up		
	000's		
	Current amount in rates (annualized)	Annual Collections with 18-month "catch up" Collection	Total Annual Increase
GRA shortfall	2,085	5,589	3,504
Diesel stab fund	755	4,642	3,887
Inuvik Stab fund	545	2,123	1,578
NW stab fund	-	1,662	1,662
YK fuel fund	-	913	913
YK water fund	-	1,103	1,103
Ft. Smith fuel fund	-	34	34
Total	3,385	16,065	12,680

4

5 Given these issues related to existing balances in stabilization funds and GRA shortfall
6 accounts and ongoing rate pressure due to increased fuel prices, coupled with the 15% cap
7 on rate increases related to base rate adjustments and shortfall rider increases, the
8 Corporation is proposing a simplified approach to its 2006/07 and 2007/08 Phase II
9 Application.

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Table 2. 2006/07 and 2007/08 Proposed Total Base Rate Adjustments, Shortfall Rider and Stabilization Fund Rider Increases by Community

Community	Total Proposed Increase				
	Residential	General	Lighting	Wholesale	Industrial
	(¢/kWh) A	(¢/kWh) B	(¢/kWh) C	(¢/kWh) D	(¢/kWh) E
Yellowknife				1.59	1.19
Behchoko	1.60	1.60	1.60		
Dettah	4.54	5.41	8.92		
Wha Ti	8.62	8.62	8.62		
Gameti	17.71	17.71	17.71		
Lutsel K'e	9.85	9.86	9.85		
Fort Smith	0.33	0.32	0.32	0.14	
Fort Resolution	2.81	2.45	4.54		
Fort Simpson	18.23	18.22	18.22		
Fort Liard	18.12	18.13	18.13		
Wrigley	28.63	28.63	28.63		
Nahanni Butte	36.99	37.00	36.99		
Jean Marie River	33.37	33.37	33.36		
Inuvik	8.38	8.39	8.39		
Norman Wells	23.21	23.21	23.21		
Tuktoyaktuk	9.87	9.87	9.87		
Fort McPherson	12.99	12.99	12.99		
Aklavik	12.22	12.22	12.22		
Deline	13.03	13.02	13.02		
Fort Good Hope	8.90	8.90	8.90		
Tulita	7.67	7.66	7.67		
Paulatuk	13.76	13.76	13.76		
Sachs Harbour	21.34	21.34	21.34		
Tsiigehtchic	7.65	7.66	7.66		
Colville Lake	23.95	23.96	23.96		
Ulukhaktok	7.69	7.70	7.69		

6

1 **Current Application**

2 The Corporation has developed its Phase II Application using a simplified approach. The
3 Corporation has prioritized collecting outstanding balances related to the 2006/07 and
4 2007/08 GRA Shortfalls and the Stabilization Funds. The Corporation is proposing this
5 simplified approach to Phase II in consideration of the 15% cap on base rate and shortfall
6 rider increases; to reduce regulatory and administrative costs in light of the limited ability to
7 rebalance rates between communities and rate classes and for reasons of intergenerational
8 equity related to collecting shortfall and stabilization fund balances relating to costs already
9 incurred to provide service to customers. Following the implementation of these rider
10 adjustments, there would be very little ability for the Corporation to adjust base rates for
11 most communities and rate classes. Therefore the Corporation is proposing only a very
12 limited scope of base rate rebalancing.

13

14 The Corporation's Application contains proposals to address the following matters:

- 15 1. Update GRA shortfall riders to collect the combined 2006/07 and 2007/08 shortfalls
16 over an 18 month period. These riders are temporary and will end when the shortfall
17 amounts are collected.
- 18 2. Update Fuel Stabilization Fund riders to track higher fuel costs (i.e. to "keep up" with
19 current fuel prices) and retire the outstanding balances (i.e. to "catch up" amounts
20 related to fuel costs already incurred) over 18 months. These riders are temporary
21 and will end or be reduced when the balances in the funds are collected.

- 1 3. Implement a Snare/Yellowknife Water Stabilization Fund rider to bring the balance in
- 2 the fund back to within the operating range of the fund. This riders is temporary and
- 3 will end or be reduced when the balances in the fund is within the operating range.
- 4 4. Propose a regular six month mechanism to update Stabilization Fund riders.
- 5 5. Rebalance base rates on a very limited basis for certain hydro communities.
- 6 6. Implementation of a rate for Stand-by Service for General Service customers.

7

8 The Corporation is not proposing or seeking approval for:

- 9 1. Changes to the cost-of-service study methods.
- 10 2. Broader rebalancing of base rates between customer classes and communities.

11

12 **Rate Stabilization Funds**

13 As part of the 1995/98 Phase I GRA negotiated settlement, the Corporation and intervenors
14 agreed to implement a series of rate stabilization funds. The Fuel Rate Stabilization funds
15 track the difference between the price of fuel built into base energy rates and the actual fuel
16 prices paid by the Corporation. When fuel prices are lower than built into rates, balances
17 accumulate in the funds to the credit of customers. When fuel prices are higher than those
18 built into rates, balances in the funds owing from customers to the Corporation accumulate.
19 Riders for these funds have been implemented to reduce previous balances in the funds
20 from time to time since the funds were established. Fuel prices have increased dramatically
21 since the Corporation filed its Phase I GRA in November, 2006 and as a result all of the Fuel
22 funds have large balances owing from customers to the Corporation.

23

1 The 1995/98 Phase I GRA negotiated settlement also established a water stabilization fund
2 for the Snare/Yellowknife system. The purpose of this fund is to track the difference between
3 long-term average hydro generation and actual hydro generation each year. When hydro
4 generation is higher than average, balances accumulate in the fund to the credit of
5 customers. When hydro generation is lower than average due to low water conditions or the
6 unavailability of hydro generation, balances accumulate in the fund owing from customers to
7 the Corporation. Since its inception, the Water Stabilization Fund has operated generally
8 within the approved operating range, meaning no refund or collection riders have been
9 necessary. However, the balances in the Water Stabilization fund are now high enough that
10 the balances must be addressed. It is important to note as well that no diesel generation
11 was built into base rates for the Snare/Yellowknife system in the 2006/07 and 2007/08
12 Phase I GRA.

13

14 **Rationale for the Proposed Simplified Phase II Approach**

15 In developing its simplified approach to Phase II, the Corporation considered the following
16 benefits to customers:

17

- 18 1. **A 15% cap on rate increases:** The Corporation has developed its proposal to follow
19 the PUB approved 15% cap on rate increases related to base rate adjustments and
20 shortfall rider increases.
- 21 2. **Cost savings by not pursuing full Phase II Application:** given the limited ability to
22 undertake rate rebalancing between customer classes and communities, the

1 Corporation considers it prudent not to pursue a full Phase II Application and incur the
2 expenses related to such a proceeding.

3 3. **Fairness:** Addressing the Rate Stabilization Fund and GRA Shortfall balances in a
4 timely way helps to ensure that the customers who used the energy while these
5 balances were accumulated are the same customers who pay off the balances,
6 without burdening future customers.

7 4. **Reduced Interest Costs:** Addressing balances related to the Rate Stabilization
8 Funds and the GRA Shortfall reduces the interest that accrues on these funds and
9 lowers the cost of these accounts to customers in the longer term.

10 5. **Rate adjustments largely related to temporary riders:** The Corporation's
11 Application contains only very limited adjustments to the base rates that have been in
12 place since January 1, 2008. Rate rider proposals relate largely to temporary, fixed
13 collection amounts.

14 6. **Balances cleared before the Next GRA:** the Rate Stabilization Fund and GRA
15 Shortfall riders proposed in this Application will help ensure that these balances are
16 addressed prior to the Corporation's next GRA.

17 7. **More Predictable Adjustment Mechanisms:** The Corporation's proposal to update
18 Stabilization Fund riders every six months will help to ensure a more predictable
19 pattern of rate adjustments and allow price variation and balance retirement
20 components of the riders to reflect the most current and best available information.

21

22 Further, the GNWT is presently undertaking a review of electricity rate regulation and
23 subsidies in the NWT. There will be opportunities for customers and other interested parties

1 to participate in public consultation as part of that review. The results of the review may
2 affect future directions in rate design and rebalancing in the NWT.

3

4 **Mitigating Measures**

5 The Corporation recognizes that this application represents a substantive rate impact for
6 customers. In developing this application, the Corporation has considered the following
7 mitigative measures to manage the rate impact on customers:

- 8 1. **An 18 month collection period for Shortfall and Stabilization Fund Riders** –
9 rather than trying to collect these balances over 12 months, the Corporation proposes
10 to collect these balances over 18 months (by the end of the 2009/10 fiscal year). This
11 reduces the rate impact compared to a 12 month collection period.
- 12 2. **Simplified approach to rate rebalancing** – given the need to focus on collecting
13 outstanding GRA shortfall and stabilization fund balances, the Corporation is
14 proposing very limited rate rebalancing between customer classes and communities.
15 The Corporation has also implemented a cap on rate increases such that no
16 community or customer class will face a combined increase in their base rates plus
17 GRA shortfall rider of more than 15 per cent.
- 18 3. **Consideration of existing subsidy programs** – The Corporation's proposal
19 considers the fact that most residential customer bills are levelized to the Yellowknife
20 rate for the first 700 kW.h of consumption each month. Therefore, the Corporation
21 has chosen to propose lower rate riders for the Snare/Yellowknife system due to the
22 fact that rate increases in Yellowknife impact residential customers for the first 700
23 kW.h of consumption each month.

1 4. **Ongoing Conservation Efforts** – In order to assist customers in managing their
2 energy bills, the Corporation continues to provide conservation information and
3 support for energy audit programs.

4 5. **Predictable Stabilization Fund Rider Adjustments** – The Corporation’s proposal to
5 adjust Stabilization Fund riders every six months will help ensure that the funds are
6 ‘keeping up’ with fuel price changes. This will help mitigate the accumulation of
7 balances in the fund and also allows the Corporation to pass along potential fuel price
8 decreases to customers in a more timely way.

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1 **APPLICATION**

2 **1.1 APPLICATION**

3 The Corporation is applying, pursuant to the provisions of the Northwest Territories Power
4 Corporation Act (“NWTPCA”) and the regulations made thereunder, and pursuant to the
5 provisions of the Public Utilities Act (“PUA”), for an order or orders of the Public Utilities
6 Board (“Board”):

- 7
- 8 a) Approving as final the Corporation’s interim retail, wholesale and industrial rates for
9 2006/07 and all previous periods.
 - 10 b) Approving as final the Corporation’s proposed 2007/08 retail, wholesale and industrial
11 energy rates as outlined in Appendix A and Schedule A.2. The Corporation proposes
12 to maintain the existing customer and demand charges for all rate classes.
 - 13 c) Approving the consolidation of the 2006/07 and 2007/08 General Rate Application
14 shortfalls after transfers from the Diesel Communities Stabilization Fund; the Inuvik
15 Stabilization Fund; the Norman Wells Stabilization Fund and the Taltson Fuel
16 Stabilization Fund to offset the GRA Shortfall amounts as described in Appendix B
17 and shown in Schedule B.1.
 - 18 d) Approving the adjusted shortfall collection riders as described in Appendix B and
19 shown in Schedule B.3.

20

- 1 e) Approving a change in the interest rate applicable to any outstanding shortfall
2 balances in place beyond October 1, 2009, as discussed in Appendix B. If the interest
3 rate change is not approved then the Corporation is seeking to recover the shortfall
4 balances over a 12-month period.
- 5 f) Approving automatic fuel stabilization fund and automatic water stabilization fund
6 riders as described in Appendix C and shown in Schedules C.1 and C.2.
- 7 g) Approving standardized dates for stabilization fund applications as described in
8 Appendix C.
- 9 h) Approving the Stand-by Rate proposal as described in Appendix D and Schedule D.
- 10 i) Approving the revisions to the Corporation's Terms and Conditions of Service
11 discussed in Appendix F.
- 12

13 **1.2 BACKGROUND**

14 The Corporation received approval in Public Utilities Board ("PUB" or "Board") Decision 19-
15 2007 for a 2006/07 Revenue Requirement of \$76.906 million and a 2007/08 Revenue
16 Requirement of \$81.389 million. Following a review and variance application related to
17 brushing expenses in certain communities, the 2006/07 and 2007/08 revenue requirements
18 were reduced to \$76.639 million and \$81.117 million respectively in Board Decision 4-2008.

19

20 The Corporation applied and received approval for interim 2006/07 rates in Board Decision
21 2-2007. The Corporation applied and received approval for 2007/08 interim rates and a
22 2006/07 shortfall rider effective January 1, 2008 in Board Decision 20-2007. Subject to a
23 small adjustment related to the revenue requirement adjustment for brushing expenses, the

1 interim rates approved in Board Decision 20-2007 fully collect the Corporation's 2007/08
2 approved revenue requirement.

3

4 **1.3 CURRENT FILING**

5 NTPC is applying for final approval of all 2006/07 and 2007/08 retail, wholesale and
6 industrial rates. In developing its present rate proposal the Corporation and its customers
7 face a number of rate pressures including:

8

- 9 1. There are substantial shortfall amounts related to the 2006/07 and 2007/08 test
10 years. If the existing shortfall riders remained in place, the shortfall including interest
11 (as approved in Board Decision 16-2008) would not be collected for over 3 years.
12 This would lead to excessive intergenerational equity to ratepayers.
- 13 2. World oil prices and diesel fuel costs have risen substantially since the 2006/07 and
14 2007/08 test year. This places further upward pressure on rates.¹
- 15 3. There are material balances in all of the existing fuel stabilization funds. These
16 balances reflect costs related to fuel expenses already incurred that need to be
17 collected.
- 18 4. There is also a balance in excess of the trigger amount in the Snare/Yellowknife
19 Water Stabilization fund.

20

¹ As an example, the 2007/08 fuel forecast assumed a NYMEX price of \$75/bbl (\$US) for the 2007/08 summer resupply season. NYMEX forecasts available August 5, 2008 are approximately \$120/bbl (\$US).

1 As a result of these combined pressures, there is a need for rate rider increases for both the
2 GRA shortfall rider and the Stabilization Fund riders. In consideration of the rate impact on
3 customers, the Corporation is applying to collect outstanding GRA shortfall balances and
4 stabilization fund balances over an 18 month period, rather than a 12 month period. The
5 Corporation's proposed approach to addressing these issues balances the needs to collect
6 the outstanding shortfall and stabilization fund balances in a timely manner and giving
7 consideration to the subsidy programs that are currently in place. It is estimated that the rate
8 impact on TPSP customers using 700 kW.h per month will be approximately \$12 per month.

9
10 After addressing rate rider adjustments for these issues, there is little if any ability to
11 implement rate rebalancing adjustments between communities and rate classes. Further,
12 most communities and rate classes are already either within a revenue to cost coverage
13 range (RCC) between 95% to 105% or facing a base rate increase plus shortfall rider
14 increase of 15%, which is the Board's long-standing threshold or cap on rate increases.
15 Therefore, in consideration of all these factors, the Corporation is proposing a simplified
16 approach to rate design and is not applying to fully rebalance rates between communities
17 and rate classes as would typically be part of a full Phase II GRA filing.

18

19 This application addresses the following subjects:

20

- 21 • Section 1.4 summarises the requested base rates, shortfall riders and stabilization
22 fund riders and the rate impact on communities and customer classes.

- 1 • Appendix A addresses base rate adjustments to reflect the revisions to the 2007/08
2 Revenue Requirement.
- 3 • Appendix B addresses the 2006/07 and 2007/08 shortfall balances and adjustments
4 to the current GRA shortfall rider.
- 5 • Appendix C addresses the current balances in the stabilization funds and stabilization
6 fund riders.
- 7 • Appendix D addresses a proposed rate for retail stand-by service.
- 8 • Appendix E provides a high level summary of preliminary cost-of-service results using
9 the allocation methods approved for the 2002/03 cost-of-service study updated for the
10 2007/08 revenue requirement and sales forecasts.
- 11 • Appendix F addresses outstanding responses to Board directives.

12 **1.4 REQUESTED BASE RATES AND RIDERS**

13 A summary of proposed base rate adjustments, shortfall rider adjustments and fuel
14 stabilization fund adjustments is provided in Schedule 1.1. The per cent increases over
15 existing base rates and riders are summarised in Schedule 1.2. The rate design considered
16 the following steps:

- 17 1. Base rates in place effective January 1, 2008 were adjusted to reflect the reduction to
18 the Corporation's 2007/08 revenue requirement related to brushing expense
19 (Column F of Schedule A.2.1).
- 20 2. Shortfall riders were calculated to collect the forecast Shortfall Balance at
21 October 1, 2008 over an 18 month period and before the time of the next GRA so that

1 these riders should not interfere with the implementation of interim rates for the next
2 GRA. Where this rider, combined with adjustments to the base rates for the brushing
3 expense reduction, would result in an increase to energy rates in the community of
4 more than 15%, the shortfall rider for that community was capped. The resulting
5 shortfall deficiency was then spread among the remaining communities who did not
6 have base rate adjustments plus shortfall riders resulting in an increase of more than
7 15% to energy rates. (Schedule 1.1 and Schedule B.3).

- 8 3. Following the calculation of the Shortfall rider, a very limited set of rate rebalancing
9 was undertaken. The base energy rates for the communities of Dettah and Fort
10 Resolution were raised as these communities had RCC ratios substantially below
11 95% while other customers on the Snare Yellowknife and Taltson systems had RCC
12 ratios higher than 100%. Energy rates in Dettah and Fort Resolution were increased
13 so that in combination with the shortfall riders in those communities there was a 15%
14 increase over the base rates plus shortfall riders in place effective January 1, 2008.
15 (Schedule 1.1). Further discussion on the limited approach to rate rebalancing is
16 provided below.

17 **1.4.1 Limited Rate Rebalancing**

18 As a result of the considerable rate pressures facing the Corporation and its customers
19 related to diesel fuel prices and the GRA shortfalls, there is little if any ability at present for
20 the Corporation to propose rate rebalancing between communities and customers classes.
21 As such, the Corporation has not completed a full analytical cost-of-service study for the
22 2007/08 test year as would typically be included in NTPC's Phase II GRAs. Preparing and

1 reviewing a cost-of-service study when there is virtually no ability to propose rate
2 rebalancing between communities and customer classes would be expensive and not in the
3 best interests of ratepayers. In the Corporation's view, customers are better off with a rate
4 design focusing on collecting outstanding amounts related to costs that have already been
5 incurred and a more simplified approach to rate rebalancing between communities. This
6 approach also saves the considerable costs of undertaking a full Phase II proceeding when
7 there is limited ability to rebalance rates. Further, the GNWT is currently conducting a review
8 of rate regulation and subsidies that may impact future rate rebalancing directions between
9 customer classes and communities.

10

11 NTPC has provided a preliminary summary 2007/08 cost-of-service results by community
12 and rate class in **Appendix E** that reflects the cost-of-service method approved in Board
13 Order 8-2003 for the 2002/03 test year updated for 2007/08 test year sales figures and
14 revenue requirements. The Corporation is not seeking approval of the cost-of-service results
15 provided in **Appendix E**, but has provided them for illustrative purposes. As a consequence
16 of this simplified approach, certain modification that the Corporation might propose to its
17 cost-of-service method and certain Board directives relating to the cost-of-service study are
18 not addressed in this application.

19

20 Other regulated jurisdictions in Canada have recognized that during times of considerable
21 rate pressure, rate rebalancing between customer classes need not be a priority. For
22 example, in 2004, the Manitoba Public Utilities Board directed across the Board rate

1 increases for all rate classes in recognition of a significant drought experienced by Manitoba
2 Hydro. In Order 101-04 the Manitoba Board stated:

3
4 In the interest of fairness and recognizing the unusual severity of the
5 effects of the recent drought, the Board has determined that the
6 impacts of the drought should be borne by all the rate classes, and
7 that sharing should be reflected in all customer classes receiving the
8 same percentage rate increase on August 1, 2004.

9
10 As indicated, future rate increases may differentiate between
11 classes.²

12
13 In British Columbia, the provincial government introduced legislation in the spring of 2008
14 amending the *Utilities Commission Act*. The provincial government noted that changes to
15 the Act were being made consistent with energy security and conservation objectives as well
16 as the government's vision for a thriving province with a globally competitive economy. One
17 of the key effects of the amendment of the Act was to suspend the British Columbia Utilities
18 Commission 2007 rate rebalancing decision that would have added a further 11 per cent
19 rate increase for residential customers over the next three years³.

² Manitoba Public Utilities Board Order 101/04, page 27.

³ British Columbia Ministry of Energy, Mines and Petroleum Resources dated March 31, 2008.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule 1.1: Rate and Rider Change Summary

Plant Number	Community	Current Base Rate ¹					Current	Current	Proposed Base Rate					Proposed	Proposed	Proposed
		Residential (¢/kWh)	General Service (¢/kWh)	Lighting ² (¢/kWh)	Wholesale (¢/kWh)	Industrial (¢/kWh)	Fuel Rider (¢/kWh)	Shortfall Rider (¢/kWh)	Residential (¢/kWh)	General Service (¢/kWh)	Lighting (¢/kWh)	Wholesale (¢/kWh)	Industrial (¢/kWh)	Fuel Rider (¢/kWh)	Water Stab Fund Rider (¢/kWh)	Shortfall Rider with 15% Cap (¢/kWh)
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
101	Yellowknife	-	-	-	13.52	10.53		0.50	-	-	-	13.46	10.07	0.45	0.55	1.15
108	Behchoko	23.06	28.83	69.96	-	-		0.50	23.01	28.78	69.90	-	-	0.45	0.55	1.15
109	Dettah	23.07	28.88	52.30	-	-		0.50	25.96	32.64	59.57	-	-	0.45	0.55	1.15
104	Wha Ti	83.44	77.37	137.75	-	-	2.14	(1.97)	83.44	77.37	137.75	-	-	12.75		(3.96)
105	Gameti	114.11	133.49	151.15	-	-	2.37	3.58	114.11	133.49	151.15	-	-	14.11		9.55
110	Lutsel K'e	73.85	68.34	120.22	-	-	2.16	0.31	73.85	68.34	120.22	-	-	12.84		(0.52)
201	Fort Smith	15.33	11.86	23.16	7.76	-		0.58	15.13	11.65	22.96	7.37	-	0.12		0.98
203	Fort Resolution	17.33	14.96	28.90	-	-		0.58	19.61	16.88	32.92	-	-	0.12		0.98
205	Fort Simpson	54.97	45.88	63.91	-	-	2.12	5.60	54.94	45.84	63.87	-	-	12.62		13.37
206	Fort Liard	59.79	52.10	102.17	-	-	2.13	5.02	59.34	51.66	101.73	-	-	12.71		13.02
207	Wrigley	104.08	113.65	158.23	-	-	2.29	11.01	103.86	113.42	158.01	-	-	13.66		28.50
208	Nahanni Butte	118.63	166.88	207.61	-	-	3.30	19.11	118.63	166.88	207.61	-	-	19.63		39.77
209	Jean Marie River	103.36	155.30	222.69	-	-	3.01	19.60	103.08	155.02	222.41	-	-	17.93		38.32
301	Inuvik	52.60	45.92	63.04	-	-	1.85	1.91	52.45	45.78	62.89	-	-	7.70		4.59
304	Norman Wells	39.79	35.70	54.80	-	-		(1.63)	39.79	35.70	54.80	-	-	23.51		(1.93)
305	Tuktoyaktuk	68.81	60.87	94.07	-	-	2.23	(2.19)	68.81	60.87	94.07	-	-	13.26		(3.35)
306	Fort McPherson	72.25	65.30	81.80	-	-	2.21	1.79	72.25	65.30	81.80	-	-	13.15		3.84
307	Aklavik	63.77	60.88	86.26	-	-	2.32	(5.34)	63.77	60.88	86.26	-	-	13.81		(4.61)
308	Deline	75.55	70.86	63.70	-	-	2.26	0.22	75.55	70.86	63.70	-	-	13.47		2.03
309	Fort Good Hope	70.42	61.43	82.44	-	-	2.23	(1.17)	70.42	61.43	82.44	-	-	13.26		(3.30)
310	Tulita	87.47	84.43	101.17	-	-	2.28	(2.00)	87.47	84.43	101.17	-	-	13.56		(5.61)
311	Paulatuk	115.01	108.24	128.20	-	-	2.34	1.86	115.01	108.24	128.20	-	-	13.91		4.06
312	Sachs Harbour	135.02	125.47	145.98	-	-	2.56	2.97	135.02	125.47	145.98	-	-	15.25		11.63
313	Tsiigehtchic	109.54	96.67	139.70	-	-	2.33	(1.22)	109.54	96.67	139.70	-	-	13.84		(5.08)
314	Colville Lake	245.30	215.29	588.10	-	-	2.68	(14.48)	245.30	215.29	588.10	-	-	15.93		(3.77)
315	Ulukhaktok	72.74	66.02	95.44	-	-	2.21	(2.28)	72.74	66.02	95.44	-	-	13.14		(5.51)

Notes:
 1. From Board Order 20-2007 rate schedules
 2. Lighting base rates estimated based on revenue divide by energy sales

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NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application

Schedule 1.2: Rate and Rider Change Summary

Plant Number	Community	% Changes without stab fund riders					% Changes with stab fund riders				
		Residential	General Service	Lighting	Wholesale	Industrial	Residential	General Service	Lighting	Wholesale	Industrial
		A	B	C	D	E	F	G	H	I	J
101	Yellowknife				4.17%	1.68%				11.31%	10.76%
108	Behchoko	2.54%	2.03%	0.84%			6.79%	5.44%	2.27%		
109	Dettah	15.00%	15.00%	15.00%			19.25%	18.41%	16.90%		
104	Wha Ti	-2.43%	-2.64%	-1.46%			10.31%	11.11%	6.25%		
105	Gameti	5.07%	4.36%	3.86%			14.75%	12.70%	11.27%		
110	Lutsel K'e	-1.11%	-1.20%	-0.69%			12.91%	13.92%	8.03%		
201	Fort Smith	1.29%	1.60%	0.85%	0.21%		2.04%	2.56%	1.35%	1.64%	
203	Fort Resolution	15.00%	15.00%	15.00%			15.67%	15.77%	15.41%		
205	Fort Simpson	12.76%	15.00%	11.12%			29.07%	33.99%	25.44%		
206	Fort Liard	11.65%	13.22%	7.04%			27.07%	30.60%	16.58%		
207	Wrigley	15.00%	13.85%	10.20%			24.39%	22.55%	16.69%		
208	Nahanni Butte	15.00%	11.11%	9.11%			26.23%	19.55%	16.08%		
209	Jean Marie River	15.00%	10.55%	7.61%			26.49%	18.76%	13.60%		
301	Inuvik	4.65%	5.32%	3.91%			14.88%	16.89%	12.56%		
304	Norman Wells	-0.78%	-0.89%	-0.56%			60.84%	68.12%	43.66%		
305	Tuktoyaktuk	-1.74%	-1.97%	-1.26%			14.34%	16.21%	10.49%		
306	Fort McPherson	2.77%	3.05%	2.46%			17.04%	18.75%	15.15%		
307	Aklavik	1.24%	1.31%	0.90%			20.11%	21.11%	14.67%		
308	Deline	2.40%	2.55%	2.84%			16.69%	17.75%	19.68%		
309	Fort Good Hope	-3.08%	-3.55%	-2.63%			12.45%	14.24%	10.66%		
310	Tulita	-4.22%	-4.39%	-3.64%			8.74%	9.05%	7.56%		
311	Paulatuk	1.88%	1.99%	1.69%			11.54%	12.24%	10.40%		
312	Sachs Harbour	6.27%	6.74%	5.81%			15.18%	16.29%	14.09%		
313	Tsiigetchic	-3.56%	-4.03%	-2.78%			6.92%	7.84%	5.44%		
314	Colville Lake	4.64%	5.33%	1.87%			10.26%	11.77%	4.16%		
315	Ulukhaktok	-4.60%	-5.07%	-3.47%			10.58%	11.67%	8.06%		

1 **APPENDIX A: FINALIZATION OF 2007/08 BASE RATES**

2 In Appendix 2 to Board Order 20-2007, the Board provided a determination of interim base
3 rate adjustments effective January 1, 2008. The interim base rate adjustments were
4 designed to allow the Corporation to fully collect the 2007/08 revenue requirement of
5 \$81.389 million approved in Board Decision 19-2007. In Decision 17-2007 the Board
6 approved the Corporation's 2007/08 miscellaneous revenues of \$0.862 million.⁴ As a result,
7 the revenues to be collected through base rate adjustments effective January 1, 2008 were
8 designed to collect \$80.527 million at approved 2007/08 sales volumes.⁵

9
10 In Decision 4-2008, the Board varied Directive 14 of Decision 13-2007 and directed the
11 Corporation to calculate its total 06/07 and 07/08 supplies and services expenses using
12 forecast brushing expenses of \$126,000 for 06/07 and \$129,000 for 07/08.⁶

13
14 By letter dated March 31, 2008 the Corporation submitted an application that requested
15 approval of a method for allocating the brushing expenditure reductions amongst the
16 communities in the test years 2006/07 and 2007/08. These adjustments were outlined in
17 Schedule 1 to that application. The Board approved this method in Decision 16-2008.⁷

18

⁴ At page 27 of Decision 17-2007 the Board found that NTPC had responded satisfactorily to Directive 20 from Decision 13-2007 related to the adjustments to miscellaneous revenues forecast.

⁵ Refer to column G of Schedule 2 of Appendix 2 to Board Decision 20-2007.

⁶ Page 10, Decision 4-2008.

⁷ Refer to page 17, Decision 16-2008.

1 As a result of the brushing adjustments, the interim base rates effective January 1, 2008 that
2 were approved in Decision 20-2007 overcollect the 2007/08 revenue requirement (as
3 adjusted for the reduction to brushing expense) by approximately \$0.272 million. Therefore,
4 the Corporation is applying to adjust the base rates in place effective January 1, 2008 to
5 reflect the revised brushing expense.

6

7 Schedule A.1 shows the calculation of the revenue to be collected from rates by community
8 with the brushing adjustment:

- 9 • Column A shows the 2007/08 Revenue Requirement by community using the method
10 described in the Corporation's Interim Rate Application.
- 11 • Column B shows the 2007/08 Revenue Requirement adjustment for the brushing
12 expense revision using the method approved in Board Decision 16-2008.
- 13 • Column C shows the 2007/08 Revenue Requirement by community following the
14 brushing expense adjustment.
- 15 • Column D shows the 2007/08 Miscellaneous revenues by community as approved in
16 Board Decision 17-2007.
- 17 • Column E shows the 2007/08 Revenues to be recovered from rates by community.

18

1 Schedule A.2.1 and Schedule A.2.2 show the requested base rate changes by community
2 and rate class and the proof of revenue at 2007/08 approved sales volumes:

3

4 • Columns A through E of Schedule A.2.1 show the 2007/08 energy sales (MW.h) by
5 community and rate class approved in Board Decision 19-2007.⁸

6 • Column F of Schedule A.2.1 shows the 2007/08 Brushing Expense adjustment by
7 community consistent with Schedule A.1.

8 • Column G of Schedule A.2.1 shows the proposed adjustment to existing base rates
9 (i.e. those approved for January 1, 2008) to reflect the brushing adjustment.

10 • Columns H through L of Schedule A.2.1 show the existing interim base rates by
11 community and customer class effective January 1, 2008 as approved in Decision 20-
12 2007.

13 • Columns M through Q of Schedule A.2.1 show the proposed final 2007/08 base rates
14 by community and rate class reflecting the brushing expense adjustment. The
15 proposed final 2007/08 base rates are the interim base rates reduced by the brushing
16 adjustment in Column G. These columns also reflect a very limited rebalancing
17 between certain communities and customer classes in the Hydro zones.

18 • Schedule A.2.2 provides a proof of revenue at the proposed Final 2007/08 rates.
19 Columns A through E show the revenues from customer and demand charges
20 consistent with the underlying forecasts approved in Decision 19-2007. Columns F
21 through J show the energy charge revenues at the proposed final 2007/08 base rates

⁸ Board Decision 19-2007 approved the Corporation's revenue requirement based on these sales forecasts.

1 and the 2007/08 approved sales volumes. Columns K through P show the total
2 revenues by community and customer class at the proposed final 2007/08 base rates
3 and sales volumes.

4

5 The Corporation is requesting final approval of the 2007/08 base energy rates detailed in
6 columns M through Q of Schedule A.2.1. The Corporation is not applying for adjustments to
7 the existing customer and demand charges and requests that those charges be approved at
8 the existing levels.

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NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule A.1: 2006/07 and 2007/08 Revenue Requirement Adjusted for Brushing Expense

Plant Number	Community	2007/08 Revenue Requirement per	2007/08 Brushing Expense	2007/08 Revenue Requirement	Misc. Revenue	Revenue To Be Recovered From Rates
		Second Refiling (\$000's)	Adjustment ¹ (\$000's)	After Brushing Expense Adj. (\$000's)		
		A	B	C=A+B	D	E
101/108/109	YK Snare System	27,479	-96	27,384	132	27,252
104	Wha Ti	1,320	-	1,320	13	1,307
105	Gameti	1,074	-	1,074	13	1,061
110	Lutzel K'e	1,094	-	1,094	13	1,081
201/203	Taltson System	6,676	-119	6,557	141	6,416
205	Fort Simpson	5,256	-3	5,254	50	5,204
206	Fort Liard	1,705	-11	1,694	13	1,681
207	Wrigley	888	-1	886	10	877
208	Nahanni Butte	632	-	632	6	626
209	Jean Marie River	484	-1	483	5	478
301	Inuvik	14,521	-41	14,479	288	14,192
304	Norman Wells	3,222	-	3,222	32	3,191
305	Tuktoyaktuk	2,638	-	2,638	22	2,616
306	Fort McPherson	2,257	-	2,257	21	2,236
307	Aklavik	1,690	-	1,690	20	1,670
308	Deline	1,794	-	1,794	14	1,780
309	Fort Good Hope	1,788	-	1,788	12	1,775
310	Tulit'a	1,681	-	1,681	13	1,668
311	Paulatuk	1,383	-	1,383	9	1,374
312	Sachs Harbour	1,009	-	1,009	7	1,001
313	Tsiigehtchic	811	-	811	10	800
314	Colville Lake	683	-	683	6	677
315	Ulukhaktok	1,306	-	1,306	13	1,293
Total		81,389	-272	81,117	862	80,255

Notes:

1. From NTPC Mar 31, 2008 shortfall and interest application. Board Order 4-2008.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application

Schedule A.2.1: Base Rate Change and Proof of Revenue with Brushing Expense Adjustment and Limited Rate Rebalancing

Plant Number	Community	2007/08 Energy Sales per GRA second refiling ²					2007/08 Brushing Expense Adj. ³ (\$000)	2007/08 Brushing Expense Adj. (¢/kWh)	Existing Base Rate ¹					Base Rates with Brushing Expense Adjustment and Limited Rebalancing				
		Residential	General Service	Lighting	Wholesale	Industrial			Residential	General Service	Lighting	Wholesale	Industrial	Residential	General Service	Lighting	Wholesale	Industrial
		(MWh)	(MWh)	(MWh)	(MWh)	(MWh)			(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q		
101	Yellowknife				165,990	3,781	(96)	(0.05)				13.52	10.53					
108	Behchoko	3,708	2,846	76				(0.05)	23.06	28.83	69.96			23.01	28.78	69.90	13.46	
109	Dettah	613	227	14				(0.05)	23.07	28.88	52.30			25.96	32.64	59.57		
201	Fort Smith	9,765	11,581	263	33,732		(119)	(0.21)	15.33	11.86	23.16	7.76		15.13	11.65	22.96	7.37	
	Taltson - Interruptible				797						3.15						3.15	
203	Fort Resolution	1,369	1,127	68				(0.21)	17.33	14.96	28.90			19.61	16.88	32.92		
104	Wha Ti	833	722	21			-	-	83.44	77.37	137.75			83.44	77.37	137.75		
105	Gameti	450	388	16			-	-	114.11	133.49	151.15			114.11	133.49	151.15		
110	Lutsel K'e	737	697	30			-	-	73.85	68.34	120.22			73.85	68.34	120.22		
205	Fort Simpson	2,918	4,534	124			(3)	(0.04)	54.97	45.88	63.91			54.94	45.84	63.87		
206	Fort Liard	1,031	1,359	46			(11)	(0.45)	59.79	52.10	102.17			59.34	51.66	101.73		
207	Wrigley	265	316	28			(1)	(0.22)	104.08	113.65	158.23			103.86	113.42	158.01		
208	Nahanni Butte	155	138	11			-	-	118.63	166.88	207.61			118.63	166.88	207.61		
209	Jean Marie River	122	111	11			(1)	(0.28)	103.36	155.30	222.69			103.08	155.02	222.41		
301	Inuvik	9,438	18,643	259			(41)	(0.15)	52.60	45.92	63.04			52.45	45.78	62.89		
304	Norman Wells	2,909	5,043	114			-	-	39.79	35.70	54.80			39.79	35.70	54.80		
305	Tuktoyaktuk	2,103	1,682	68			-	-	68.81	60.87	94.07			68.81	60.87	94.07		
306	Fort McPherson	1,545	1,550	59			-	-	72.25	65.30	81.80			72.25	65.30	81.80		
307	Aklavik	1,301	1,190	55			-	-	63.77	60.88	86.26			63.77	60.88	86.26		
308	Deline	1,163	1,174	34			-	-	75.55	70.86	63.70			75.55	70.86	63.70		
309	Fort Good Hope	1,230	1,332	57			-	-	70.42	61.43	82.44			70.42	61.43	82.44		
310	Tulita	1,033	821	36			-	-	87.47	84.43	101.17			87.47	84.43	101.17		
311	Paulatuk	531	662	25			-	-	115.01	108.24	128.20			115.01	108.24	128.20		
312	Sachs Harbour	261	474	31			-	-	135.02	125.47	145.98			135.02	125.47	145.98		
313	Tsiigehtchic	373	362	21			-	-	109.54	96.67	139.70			109.54	96.67	139.70		
314	Colville Lake	146	134	6			-	-	245.30	215.29	588.10			245.30	215.29	588.10		
315	Ulukhaktok	806	974	25			-	-	72.74	66.02	95.44			72.74	66.02	95.44		

Notes:

1. From Board Order 20-2007 rate schedules

2. Energy Sales from Nov 30 2007 refiling Schedule A.1 to Schedule A.27.

3. From NTPC March 31, 2008 GRA shortfall and interest application. Plant 101 Yellowknife Brushing expense adjustment includes Behchoko and Dettah. Fort Smith Adjustment includes Ft. Resolution.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application

Schedule A.2.2: Base Rate Change and Proof of Revenue with Brushing Expense Adjustment and Limited Rate Rebalancing

Plant Number	Community	Revenue - Customer charges, Demand charges ¹					Revenue - Energy Charge					Total Revenue					Total (\$000)
		Residential (\$000)	General Service (\$000)	Lighting (\$000)	Wholesale (\$000)	Industrial (\$000)	Residential (\$000)	General Service (\$000)	Lighting (\$000)	Wholesale (\$000)	Industrial (\$000)	Residential (\$000)	General Service (\$000)	Lighting (\$000)	Wholesale (\$000)	Industrial (\$000)	
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
101	Yellowknife				2,857	168	-	-	-	22,337	381	-	-	-	25,194	549	25,743
108	Behchoko	101	110				853	819	53	-	-	954	929	53	-	-	1,936
109	Dettah	19	13				159	74	9	-	-	178	87	9	-	-	274
201	Fort Smith	217	391				1,477	1,349	60	2,486	-	1,694	1,740	60	2,486	-	5,981
	Taltson - Interruptible						-	-	-	25	-	-	-	-	25	-	25
203	Fort Resolution	45	54				269	190	22	-	-	314	244	22	-	-	580
104	Wha Ti	28	30				695	558	28	-	-	723	589	28	-	-	1,340
105	Gameti	17	16				513	517	24	-	-	530	534	24	-	-	1,088
110	Lutsel K'e	26	27				544	476	36	-	-	571	503	36	-	-	1,109
205	Fort Simpson	107	166				1,603	2,078	79	-	-	1,711	2,244	79	-	-	4,034
206	Fort Liard	37	82				612	702	47	-	-	649	784	47	-	-	1,480
207	Wrigley	11	18				275	358	45	-	-	286	376	45	-	-	707
208	Nahanni Butte	8	8				184	252	23	-	-	191	261	23	-	-	475
209	Jean Marie River	5	7				126	172	24	-	-	131	179	24	-	-	334
301	Inuvik	314	611				4,950	8,534	163	-	-	5,264	9,145	163	-	-	14,572
304	Norman Wells	81	165				1,158	1,800	63	-	-	1,239	1,965	63	-	-	3,267
305	Tuktoyaktuk	71	75				1,447	1,024	64	-	-	1,518	1,099	64	-	-	2,681
306	Fort McPherson	60	58				1,116	1,012	48	-	-	1,176	1,070	48	-	-	2,295
307	Aklavik	53	54				830	725	48	-	-	883	779	48	-	-	1,710
308	Deline	45	48				879	832	22	-	-	924	880	22	-	-	1,826
309	Fort Good Hope	42	47				866	818	47	-	-	908	865	47	-	-	1,820
310	Tulita	35	41				904	693	36	-	-	939	734	36	-	-	1,709
311	Paulatuk	20	31				611	717	32	-	-	630	747	32	-	-	1,409
312	Sachs Harbour	11	18				352	594	45	-	-	363	613	45	-	-	1,021
313	Tsiigehtchic	16	17				409	350	30	-	-	424	366	30	-	-	820
314	Colville Lake	8	5				358	289	34	-	-	365	294	34	-	-	693
315	Ulukhaktok	32	40				586	643	24	-	-	618	683	24	-	-	1,325
Total		1,411	2,132	-	2,857	168	21,774	25,579	1,105	24,848	381	23,185	27,710	1,105	27,705	549	80,254

Notes:

1. Customer and Demand related revenue from Nov 30 2007 refiling Schedule A.1 to Schedule A.27.

1 **APPENDIX B: FINALIZATION OF SHORTFALL BALANCES AND RIDERS**

2 In an application dated March 31, 2008, the Corporation provided a calculation of the
3 2006/07 test year shortfall as at December 31, 2007 following the implementation of the
4 2006/07 revenue requirement adjustment related to brushing expense. The Board confirmed
5 and approved NTPC's calculation of the 2006/07 test year shortfall as at December 31, 2007
6 in Board Decision 16-2008 (\$1.818 million). The Board also allowed the Corporation to
7 charge interest at a rate of 2.31% on the 2006/07 shortfall for the period from April 1, 2007
8 to December 31, 2007. For the period beyond the December 31, 2007, the Board allowed
9 NTPC to apply short-term interest to the actual outstanding receivable monthly at a level
10 equal to 50% of the Bank of Canada Prime Business interest rate.⁹

11
12 In the March 31, 2008 application, the Corporation also provided a calculation of the
13 2007/08 shortfall as at March 31, 2008 reflecting the brushing expense adjustment (\$11.856
14 million). The Board confirmed and approved this calculation in Decision 16-2008. The Board
15 also allowed the Corporation to charge interest at a rate of 3.0% on the 07/08 shortfall on a
16 mid-year basis for 2007/08. For the period starting April 1, 2008 until full collection of the
17 2007/08 shortfall the Corporation is permitted to apply short-term interest to the actual
18 outstanding receivable monthly at a level equal to 50% of the Bank of Canada Prime
19 Business interest rate.¹⁰

20

⁹ Decision 16-2008, page 17.

¹⁰ Decision 16-2008, page 17.

1 It is important to note that this reflects a very low short-term interest rate. As a result, it is not
2 reasonable to customers or the Corporation for these outstanding balances to remain in
3 place for extended periods. One of the implications of allowing these balances to persist
4 beyond the next 12 months is that the Corporation has a limited ability to obtain financing at
5 short-term interest rates. Allowing these balances to continue indefinitely may impact the
6 Corporation's ability to manage its short-term financing and put pressure on other uses of
7 short-term financing, including the Corporation's capital program. This would ultimately
8 threaten the ability of the Corporation to earn its approved return on ratebase. Accordingly,
9 the Corporation is applying for approval to charge an interest rate of prime less 50 basis
10 points on any shortfall balances outstanding beyond October 1, 2009. This is the same
11 interest rate presently applied to the stabilization funds. In the event that the interest rate
12 change after 12 months is not approved, the Corporation will seek to collect the outstanding
13 shortfall amounts over a 12 month period instead of an 18 month period.

14
15 In Decision 20-2007, the Board approved shortfall riders by community effective January 1,
16 2008 designed to collect the 2006/07 shortfall over approximately a 12 month period,
17 stating:

18
19 For the purposes of calculating the Board-determined 2006/07 under
20 recovery rider, the Board has prorated the \$2.085 million amount to
21 each of the communities on the basis of the unrecovered balance as
22 of March 31, 2007 and used the 2007/08 volumes to arrive at the
23 rider amount by community. These calculations are shown in

1 Schedule 1 of Appendix 2. The Board expects its estimates would
2 result in a reasonable 2006/07 rider by community intended to
3 recover the 2006/07 unrecovered amounts as of December 31, 2007
4 over a 12 month period, for purposes of interim rates. However, since
5 these are estimates, NTPC is directed to update the 2006/07
6 unrecovered balances by community at the time it files its application
7 for recovery of the 2007/08 revenue under recoveries and
8 incorporate all revenue under recovery amounts at that time into a
9 single rider.¹¹

10
11 Consistent with the Board's direction, the Corporation is applying to consolidate the 2006/07
12 and 2007/08 shortfall receivables into one shortfall receivable by community. The
13 Corporation is also applying to adjust the shortfall riders by community. Schedule B.1 shows
14 the calculation of the Consolidated Shortfall at March 31, 2008:

- 15
- 16 • Column A shows the 2006/07 receivable by community as at March 31, 2007
17 following the brushing expense adjustment.
 - 18 • Column B shows the 2006/07 receivable by community as at December 31, 2007 by
19 community consistent with Board Decision 16-2008.
 - 20 • Column C shows the interest on the average balance at 2.31% interest as approved
21 in Board Decision 16-2008.

¹¹ Decision 20-2007, page 5.

- 1 • Column D shows the 2006/07 shortfall receivable including interest as at December
2 31, 2007.
- 3 • Columns E through L show the monthly balances for the 2006/07 shortfall, less actual
4 shortfall rider collections by month, plus actual interest consistent with the method
5 approved in Decision 16-2008 for the period January 2008 through March 31, 2008.
- 6 • Column M shows the 2006/07 actual shortfall balance as at March 31, 2008.
- 7 • Column N shows the 2007/08 shortfall balance with the brushing adjustment as at
8 March 31, 2008, consistent with Decision 16-2008.
- 9 • Column O shows the 2007/08 revenue at existing rates.¹²
- 10 • Column P shows the transfers from the fuel stabilization funds credited against the
11 2007/08 GRA shortfall as described in the Corporation's December 18, 2007 filing
12 (Schedules 2, 4, 6 and 8 to that filing).
- 13 • Column Q shows the 2007/08 Shortfall following the stabilization fund transfers and
14 the brushing adjustments as at March 31, 2008.
- 15 • Column R shows the calculation of interest on the 2007/08 shortfall mid-year balance
16 consistent with the method approved in Decision 16-2008.
- 17 • Column S shows the 2007/08 shortfall balance including interest as at
18 March 31, 2008.
- 19 • Column T shows the consolidated 2006/07 and 2007/08 shortfall balance by
20 community, including interest as at March 31, 2008 of **\$9.339 million**.
- 21

¹² Note that this includes 3 months of revenue at the rates approved effective January 1, 2008.

1 The shortfall rider currently in place, effective January 1, 2008 has been collecting
2 approximately \$0.225 million per month.¹³ If the current shortfall rider remains in place, it
3 would take in excess of 3 years to collect the outstanding consolidated shortfall plus
4 approved interest.¹⁴

5

6 The Corporation is applying to collect the forecast balances in place at September 30, 2008.

7 Schedule B.2 shows the forecast shortfall balance at September 30, 2008:

8

- 9 • Column A shows the actual Consolidated Shortfall Balance at March 31, 2008.
- 10 • Column B shows the forecast rider collections from April 2008 through September
11 2008.
- 12 • Column C shows forecast base rate overcollection due to the existing base rates
13 not yet being adjusted to reflect the brushing expense adjustment for the period
14 from April 2008 through September 2008.¹⁵
- 15 • Column D shows the interest applied to the shortfall balance at the end of each
16 month for the period April 2008 through September 2008.
- 17 • Column E shows the forecast Consolidated Shortfall Balance at
18 September 30, 2008 of **\$8.383 million**.

19

¹³ Reflects actual collections for February and March 2008.

¹⁴ \$13.495 million divided by \$0.225 average monthly collections equals 60 months.

¹⁵ The sales volumes used correspond to the Corporation's most recent load forecast for the 2008/09 fiscal year. The shortfall rider collections are based on the existing shortfall rider in place effective January 1, 2008. The Overcollection of base rate amounts due to the brushing adjustments are based on the calculations described in Schedule A.2.2 Column G.

1 Schedule B.3 shows the proposed shortfall rider adjustments effective October 1, 2008:

2

3 • Column A shows the forecast Consolidated Shortfall Balance by community at
4 October 1, 2008.

5 • Column B shows the Forecast sales (kW.h) from October 1, 2008 through
6 March 31, 2010.

7 • Column C shows the calculation of the shortfall rider required to collect the
8 consolidated shortfall over approximately an 18 month period to March 31, 2010.

9 • Column D shows the calculation of the shortfall rider after a 15% cap is applied to
10 communities in consideration of the shortfall rider and base energy rates in place
11 effective January 1, 2008.

12

13 The Corporation is applying for approval to implement these riders until the consolidated
14 shortfall is fully collected. Following collection of the consolidated shortfall the Corporation
15 will file a reconciliation of rider collections and shortfall balances by community.

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**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule B.2: Consolidated Shortfall Continuity from Apr 2008 to Sept 2008**

		Actual Consolidated Shortfall	Forecast Activities			
Plant Number	Community	Consolidated 2006/07 and 2007/08 Shortfall @ Mar 31,2008 with Interest'¹ (\$000's)	2006/07 Shortfall Rider Collection From Apr 2008 - Sep 2008 (\$000's)	less: Base Rate Over Collection due to Brushing adj. From Apr 2008 - Sep 2008 (\$000's)	Interest From Apr 2008 - Sep 2008 2.38%	Monthend Balance at Sep 2008 (\$000's)
		A	B	C	D	E
101/108/109	YK Snare System	3,719	411	-44	41	3,306
104	Wha Ti	-104	-12	0	-1	-92
105	Gameti	131	13	0	1	120
110	Lutzel K'e	-11	2	0	0	-13
201/203	Taltson System	1,108	151	-54	12	914
205	Fort Simpson	1,915	183	-1	22	1,753
206	Fort Liard	456	47	-4	5	410
207	Wrigley	312	28	-1	4	286
208	Nahanni Butte	266	29	0	3	240
209	Jean Marie River	212	20	0	2	194
301	Inuvik	2,362	243	-19	27	2,127
304	Norman Wells	-365	-60	0	-4	-309
305	Tuktoyaktuk	-216	-33	0	-2	-186
306	Fort McPherson	190	22	0	2	170
307	Aklavik	-247	-59	0	-3	-191
308	Deline	76	2	0	1	74
309	Fort Good Hope	-152	-13	0	-2	-141
310	Tulit'a	-138	-18	0	-2	-121
311	Paulatuk	56	10	0	1	46
312	Sachs Harbour	127	10	0	1	118
313	Tsiigehtchic	-28	-3	0	0	-25
314	Colville Lake	-121	-18	0	-1	-104
315	Ulukhaktok	-208	-17	0	-2	-194
Total		9,339	938	-123	105	8,383

Notes:

1. From Schedule B.1

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**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule B.3: Proposed Shortfall Rider at October 1, 2008**

Plant Number	Community	Shortfall Balance at Oct. 1, 2008 ¹ (\$000's)	Forecast Sales From		Proposed Shortfall Rider at Oct. 1, 2008 with		Current Shortfall Rider per Board Order 20-2007 (¢/kWh)
			Oct. 1, 2008 - Mar. 31, 2010 (MWh)	Shortfall Rider with No Cap (¢/kWh)	15% Cap (¢/kWh)		
		A	B	C	D	E	
101/108/109	YK Snare System	3,306	301,607	1.10	1.15	0.50	
104	Wha Ti	-92	2,303	(4.01)	(3.96)	(1.97)	
105	Gameti	120	1,260	9.49	9.55	3.58	
110	Lutzel K'e	-13	2,280	(0.57)	(0.52)	0.31	
201/203	Taltson System	914	98,247	0.93	0.98	0.58	
205	Fort Simpson	1,753	11,978	14.63	13.37	5.60	
206	Fort Liard	410	3,166	12.96	13.02	5.02	
207	Wrigley	286	864	33.15	28.50	11.01	
208	Nahanni Butte	240	538	44.52	39.77	19.11	
209	Jean Marie River	194	362	53.56	38.32	19.60	
301	Inuvik	2,127	46,857	4.54	4.59	1.91	
304	Norman Wells	-309	15,548	(1.99)	(1.93)	(1.63)	
305	Tuktoyaktuk	-186	5,453	(3.40)	(3.35)	(2.19)	
306	Fort McPherson	170	4,482	3.78	3.84	1.79	
307	Aklavik	-191	4,088	(4.67)	(4.61)	(5.34)	
308	Deline	74	3,751	1.98	2.03	0.22	
309	Fort Good Hope	-141	4,191	(3.36)	(3.30)	(1.17)	
310	Tulit'a	-121	2,132	(5.67)	(5.61)	(2.00)	
311	Paulatuk	46	1,145	4.00	4.06	1.86	
312	Sachs Harbour	118	1,023	11.58	11.63	2.97	
313	Tsiigehtchic	-25	491	(5.13)	(5.08)	(1.22)	
314	Colville Lake	-104	2,721	(3.83)	(3.77)	(14.48)	
315	Ulukhaktok	-194	3,476	(5.57)	(5.51)	(2.28)	
Total		8,383	517,964				

Notes:

1. From Schedule B.2

1 **APPENDIX C: ADJUSTMENTS TO STABILIZATION FUND BALANCES AND RIDERS**

2 As part of the negotiated settlement related to the Corporation's 1995/98 Phase I GRA, the
3 Corporation and its customers agreed to implement a series of stabilization funds. The
4 purpose of the funds was to mitigate the adverse impact on rates of unanticipated changes
5 in fuel prices and deviations of hydro conditions from normal. One of the key attributes of the
6 funds was the implementation of an automatic rider to collect or refund balances in the
7 funds, the 1995/98 negotiated settlement stated:

8

9 An "automatic" rider would come into effect, subject only to Board
10 approval of the calculation of the amount of the rider, when the
11 amount in the Fund exceeds the Fund range sufficiently such that the
12 Corporation determines that it is prudent to implement a rider.¹⁶

13

14 These stabilization funds have operated to the benefit of both the Corporation and its
15 customers since their inception. However, the trigger levels established in the 1995/98
16 negotiated settlement were based on the range of fuel prices experienced at that time.
17 Today the Corporation and its customers are facing substantially higher fuel prices. The
18 2007/08 test year fuel forecasts for the 2008 summer resupply were based on NYMEX
19 futures for Light Sweet Crude Oil at approximately \$75/bbl (\$US) compared to more recent
20 prices of upwards of \$120/bbl (\$US). Riders are now required for many of the funds to
21 address price variations from the fuel prices built into base rates (the "keep-up" component

1 of the riders). There are also substantial balances owing from customers in all of the funds
2 and riders are required to retire these balances (the “catch-up” component of the rider).

3 As a result, the Corporation requires adjustments to the existing stabilization fund riders both
4 to keep up with current diesel fuel prices and to retire the balances in the funds. Proposals
5 for each of the fuel riders are described in this section.

6

7 Actual stabilization fund balances at year ended March 31, 2008 and forecasts for 2008/09
8 and 2009/10 are provided for each fund (Schedules C.3.1 through Schedules C.8.3).
9 2007/08 year end balances also reflect monthly transfers from the fuel stabilization funds to
10 the 2007/08 GRA shortfall for each month from April 2007 through December 2007.

11 Transfers to the GRA shortfall are the same as those presented in the Corporation’s
12 December 18, 2007 filing of supplemental information to its 2nd Phase I refiling. No transfers
13 are proposed for January 2008 through March 2008 as interim rates were in place for those
14 months that were designed to collect the Corporation’s full 2007/08 revenue requirement.

15

16 Illustrative forecasts for 2008/09 and 2009/10 have also been prepared and are presented in
17 Schedules C.3.1 through Schedules C.8.3. Fuel price changes were prepared for each
18 community using the best available information at the time this application was prepared and
19 the methods described in the Corporation’s 2006/07 and 2007/08 General Rate
20 Application¹⁷. For summer resupply communities¹⁷ it was assumed that prices changes would
21 be implemented in July 2009 based on NYMEX futures for June. For winter resupply

¹⁶ Page 5, bullet (e) (iii). 1995/98 Phase I Negotiated Settlement.

¹⁷ Refer to the Corporation’s response to TGC.NTPC-40 from the 2006/07 and 2007/08 Phase I Application.

1 communities it was assumed that price changes would be implemented in January 2009 and
2 January 2010 based on NYMEX futures for December of 2008 and December of 2009
3 respectively. For other communities fuel prices use estimates prepared for summer 2008
4 and summer 2009. Details of fuel price forecasts by community are included in Appendix
5 C.1 through Appendix C.6. Sales and generation volumes reflect the best available
6 information at the time of this Application. However, it is important to note that all the
7 stabilization funds are calculated using actual generation; actual fuel prices and actual rider
8 collections. Fuel volumes in the stabilization funds use the PUB approved efficiencies for
9 each plant.

10

11 **Diesel Fuel Stabilization Fund**

12 The forecast balance at October 1, 2008 in the Diesel Fuel Stabilization Fund, following the
13 transfers finalized in this application is **\$2.375 million** reflecting an amount owing from
14 customers to NTPC. The established trigger for this fund is \$1 million. Variances arise in the
15 diesel fund as diesel fuel prices at present are approximately 15 cents per litre higher than
16 forecast for the 2007/08 test year. That variance is expected to increase to approximately 26
17 cents/litre once current world diesel prices flow through to NTPC's fuel expense. The
18 Corporation is proposing both a "keep-up" component to the rider to address price variations
19 and a "catch-up" component to the rider to retire the balances in the fund.

20

1 **Inuvik Fuel Stabilization Fund**

2 The forecast balance at October 1, 2008 in the Inuvik Fuel Stabilization Fund, following the
3 transfers finalized in this application, is **\$0.859** million (reflecting an amount owing from
4 customers to NTPC). The established trigger for this fund is \$0.250 million. The Corporation
5 is proposing both a “keep-up” component to the rider to address price variations and a
6 “catch-up” component to the rider to retire the balances in the fund.

7
8 **Norman Wells Fuel Stabilization Fund**

9 The forecast balance in the Norman Wells Fuel Stabilization Fund, following the transfers
10 finalized in this application, is **\$0.740** million at October 1, 2008 (reflecting an amount owing
11 from customers to NTPC). The established trigger for this fund is \$0.100 million. The
12 Corporation is proposing both a “keep-up” component to the rider to address price variations
13 and a “catch-up” component to the rider to retire the balances in the fund.

14
15 **Fort Smith Fuel Stabilization Fund**

16 The forecast balance at October 1, 2008 in the Taltson Fuel Stabilization Fund, following the
17 transfer proposed in this application is **\$0.050** million reflecting an amount owing from NTPC
18 to customers. The established trigger for this Fund is \$0. Since the primary generation
19 source for this system is hydro generation, the Corporation is proposing only a “catch-up”
20 component to the rider to retire the balance in the fund.

21

1 **Snare/Yellowknife Fuel Stabilization Fund**

2 The forecast balance in the Snare/Yellowknife Fuel Stabilization Fund is **\$1.369** million at
3 October 1, 2008. The established trigger for the fund is \$1 million. It is important to note that
4 there was no diesel fuel expense built into the revenue requirement for the
5 Snare/Yellowknife system in the 2006/07 & 2007/08 Phase I GRA. Since the primary
6 generation source for this system is hydro generation, and rate changes in Yellowknife
7 ultimately affect all residential customer through the TPSP, the Corporation is proposing only
8 a “catch-up” component to the rider to retire the balance in the fund.

9

10 **Snare/Yellowknife Water Stabilization Fund**

11 In addition to a rider for the Snare/Yellowknife Fuel Stabilization fund, a rider is also required
12 to address the current balance in the Snare/Yellowknife Water Stabilization. The fund
13 balance is forecast to be **\$4.654** million at October 1, 2008. The established trigger for this
14 fund is \$3 million. Charges to the water stabilization fund arise as a result of the
15 unavailability of hydro generation due to low water or other factors.

16

17 The range established for the water stabilization fund at the time of the 1995/98 Phase I
18 negotiated settlement was developed based on fuel prices at the time of that application.
19 Fuel prices are substantially higher today, and as a result increment diesel generation
20 requirements drive higher balances in the water stabilization fund. It should be noted that
21 this is the first time in the 12 year history of the fund that a rider is being proposed to
22 address balances in the water stabilization fund.

23

1 **Stabilization Fund Rider Proposals**

2 Schedule C.1 shows the calculation of the proposed stabilization fund riders. For the Diesel
3 Community Fund, the Inuvik Fund and the Norman Wells Fund, the proposed stabilization
4 fund riders include a Price Variation Component (“keep up” portion) that is designed to track
5 the difference in fuel prices between those assumed in the 2007/08 test year and current
6 fuel prices. For the diesel community stabilization fund, the fuel price forecast uses the
7 weighted average forecast to be in place effective January 1, 2009. The calculation of this
8 portion of the rider is shown in rows 1 through 9 of Schedule C.1. This is the estimated
9 minimum rider that is necessary simply to ensure that the balances in these funds do not
10 accumulate any further.

11
12 No Price Variation Component is proposed for the Yellowknife Fuel Fund or the Fort Smith
13 Fuel Fund as these are largely stand-by generation plants at present. Since the primary
14 generation source for these systems is hydro generation, and rate changes in Yellowknife
15 ultimately affect all residential customer through the TPSP, the Corporation is proposing only
16 a “catch-up” component to the rider to retire the balance in these funds.

17
18 Each of the Fuel Stabilization Funds (including Fort Smith and Snare/Yellowknife) and the
19 Snare/Yellowknife Water Stabilization Fund has a Balance Retirement Component. This
20 portion of the rider is designed to collect the full amount of the balances in the fund at
21 October 1, 2008 over an 18 month period. For the Snare/Yellowknife Water Stabilization
22 Fund, the rider is designed only to collect the amount by which the fund exceeds the \$3
23 million trigger amount at October 1, 2008. The calculation of this portion of each rider is

1 shown in rows 10 through 13 of Schedule C.1. Proposed Stabilization Fund Riders effective
2 October 1, 2008 are shown on Row 14 of Schedule C.1. The Diesel community rider to
3 applied in each community is shown in Schedule C.2, consistent with the indexing method
4 approved in Decision 20-2007.

5
6 Sales and generation forecasts used in this application are estimates based on the best
7 available information at the time this Application was prepared. It should be noted that the
8 sales used to calculate the Diesel Community fuel rider have been indexed, using the same
9 indices outlined in Schedule C.2. Revenues from the riders are based on un-indexed sales.
10 The Corporation will apply actual rider collections against the stabilization fund balances
11 each month.

12

13 **Standardized Rider Adjustment Dates**

14 While the Corporation has applied in this application for riders that would retire the balances
15 at October 1, 2008 in approximately 18 months, the Corporation recognizes the need to
16 update these riders from time to time. Further, the Corporation notes that fuel prices have
17 been extremely volatile recently and that fuel price changes can contribute to balances or
18 credits in the stabilization funds to a significant degree. Therefore, the Corporation proposes
19 to file Stabilization Fund Adjustment Applications on a regular schedule. The Corporation
20 respectfully requests approval to file Applications for these adjustments by February 15 and
21 August 15 each year for rider adjustments to be implemented effective April 1 and October 1
22 each year respectively.

1 In the Corporation's view, this will benefit customers by providing more regular and
2 predictable price changes. It will also ensure fairness to future customers by improving the
3 timing between when fuel cost increases are incurred and when those costs are collected
4 from customers. Further, the proposed timing of the rider changes avoid the summer and
5 winter holiday periods. Finally, in the Corporation's view this is consistent with the intent of
6 the 1995/98 Phase I negotiated settlement that the rider adjustments be automatic, with
7 Board review of the calculation of proposed riders as necessary.

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Schedule C.1: Proposed Stabilization Fund Riders

	Diesel Fund	Inuvik - Gas Portion	Inuvik - Diesel Portion	Inuvik Total	Norman Wells Fuel Fund	Yellowknife Fuel Fund	Yellowknife Water Fund	Ft. Smith Fuel Fund
	A	B	C	D	E	F	G	H
1 GRA Approved Weighted Average Fuel Price (\$/Litre)	0.948 (\$/Litre)	0.430 (\$/m ³)	0.797 (\$/Litre)		0.279 (\$/kWh)			
2 Fuel Price (\$/Litre) ¹	1.239 (\$/Litre)	0.563 (\$/m ³)	1.299 (\$/Litre)		0.440 (\$/kWh)			
3 Difference (L2-L1)	0.291 (\$/Litre)	0.133 (\$/m ³)	0.502 (\$/Litre)		0.161 (\$/kWh)			
4 Approved Average Efficiency (kWh/L)	3.598 (kWh/Litre)	3.399 (kWh/m ³)	3.635 (kWh/Litre)					
5 Average Cents/kWh Diesel Fuel Expense Shortfall(L3/L4 ¹)	8.102 (¢/kWh)	3.923 (¢/kWh)	13.816 (¢/kWh)					
6 Forecast Generation (Oct 2008 - Mar 2010)	62,322 (MWh)	45,075 (MWh)	7,091 (MWh)		18,067 (MWh)			
7 Forecast Fuel Expense Shortfall (\$000) (L5*L6)	5,049	1,768	980	2,748	2,916			
8 Forecast Sales (Oct 2008 - Mar 2010)	58,843 (MWh)			46,857 (MWh)	15,548 (MWh)			
9 Requested Fuel Price Variance Component (L7/L8)	0.0858 (\$/kWh)			0.0586 (\$/kWh)	0.1875 (\$/kWh)			
10 Forecast Balance at Sep 30, 2008 (\$000)	2,375			859	740	1,369	4,654	50
11 Proposed Balance to Collect (\$000)	2,375			859	740	1,369	1,654	50
12 Forecast Sales (Oct 2008 - Mar 2010)	58,843 (MWh)			46,857 (MWh)	15,548 (MWh)	301,607 (MWh)	301,607 (MWh)	42,104 (MWh)
13 Requested Balance Retirement Component (L11/L12)	0.0404 (\$/kWh)			0.0183 (\$/kWh)	0.0476 (\$/kWh)	0.0045 (\$/kWh)	0.0055 (\$/kWh)	0.0012 (\$/kWh)
14 Total Requested Stabilization Fund Rider (I+M)	0.1262 (\$/kWh)			0.0770 (\$/kWh)	0.2351 (\$/kWh)	0.0045 (\$/kWh)	0.0055 (\$/kWh)	0.0012 (\$/kWh)

Notes:

1. Diesel Community Fuel price based on the weighted average price at January 2009. Inuvik gas and diesel price at August 2008. Norman Wells Fuel Fund price at August 200

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**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.2: Proposed Diesel Communities Stabilization Fund Riders**

Plant Number	Community	Fuel Rider Index¹	Resulting Diesel Rider at 12.62 cents/kW.h Unindexed
104	Wha Ti	1.010	12.75
105	Gameti	1.118	14.11
110	Lutsel K'e	1.018	12.84
205	Fort Simpson	1.000	12.62
206	Fort Liard	1.007	12.71
207	Wrigley	1.083	13.66
208	Nahanni Butte	1.556	19.63
209	Jean Marie River	1.421	17.93
305	Tuktoyaktuk	1.051	13.26
306	Fort McPherson	1.042	13.15
307	Aklavik	1.095	13.81
308	Deline	1.067	13.47
309	Fort Good Hope	1.051	13.26
310	Tulita	1.075	13.56
311	Paulatuk	1.102	13.91
312	Sachs Harbour	1.208	15.25
313	Tsiigehtchic	1.097	13.84
314	Colville Lake	1.263	15.93
315	Ulukhaktok	1.041	13.14

Notes:

1. Fuel Rider Index from Decision 20 - 2007 Schedule 5.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.3.1: DIESEL COMMUNITIES STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.		Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	Actual Diesel Generation (MWh)	3,290	3,129	2,836	2,874	2,931	3,052	3,692	3,783	4,137	4,311	3,951	4,012
2	Approved Efficiency (kWh/L)	3.593	3.596	3.600	3.599	3.598	3.597	3.587	3.592	3.586	3.596	3.592	3.588
3	Litre of Fuel Required (000 Litre)	916	870	788	799	815	848	1,029	1,053	1,154	1,199	1,100	1,118
4	Actual Diesel Price (weighted average) (\$/L)	0.970	1.011	1.013	1.012	1.029	1.024	1.029	1.037	1.033	1.036	1.067	1.097
5	Approved Diesel Price in Rates (weighted average) (\$/L)	0.944	0.947	0.943	0.941	0.946	0.945	0.944	0.953	0.942	0.945	0.944	0.948
6	Increase (Decrease) in Fuel Price from Rates (\$) (L4 - L5)	0.025	0.065	0.070	0.070	0.083	0.079	0.084	0.084	0.091	0.091	0.122	0.149
7	Additional Diesel Cost (\$000)	23	56	55	56	68	67	87	88	105	109	135	167
	Fuel Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	1,658	1,840	1,860	1,785	1,595	1,735	1,680	1,649	1,694	1,645	1,992	1,810
9	Adjustment to opening balance for 06/07 Price adjustment.	368											
10	Refund/(Collection) Rider	-391	-426	-336	-393	-335	-385	-450	-382	-543	229	-325	-464
11	Stab. Fund Transfer to GRA Shortfall	340	288	289	220	320	281	324	331	382			
12	Additional Diesel Cost (L7)	23	56	55	56	68	67	87	88	105	109	135	167
13	Fuel Swap	-167	93	-91	-81	79	-25						
14	Closing Balance Before Interest (L8 + L9 + L10 + L11 + L12)	1,831	1,851	1,777	1,587	1,726	1,672	1,641	1,686	1,637	1,984	1,802	1,512
15	Interest Rate (Prime less 50 points)	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
16	Interest (Charged) Earned	8	9	8	8	8	8	8	8	8	9	7	6
17	Closing Balance (L13+L15)	1,840	1,860	1,785	1,595	1,735	1,680	1,649	1,694	1,645	1,992	1,810	1,518

Notes:

1. The calculations are based on actual diesel generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The fuel prices used are those approved by the Public Utilities Board in the most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.3.2: DIESEL COMMUNITIES STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.		Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
1	Forecast Diesel Generation (MWh)	3,103	2,951	2,675	2,711	2,765	2,879	3,483	3,569	3,902	4,067	3,727	3,784
2	Approved Efficiency (kWh/L)	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598
3	Litre of Fuel Required (000 Litre)	862	820	744	753	768	800	968	992	1,085	1,130	1,036	1,052
4	Forecast Diesel Price (weighted average) (\$/L)	1.097	1.113	1.154	1.266	1.266	1.266	1.266	1.266	1.266	1.239	1.239	1.239
5	Approved Diesel Price in Rates (weighted average) (\$/L)	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948
6	Increase (Decrease) in Fuel Price from Rates (\$) (L4 - L5)	0.149	0.166	0.206	0.319	0.319	0.319	0.319	0.319	0.319	0.291	0.291	0.291
7	Additional Diesel Cost (\$000)	129	136	153	240	245	255	308	316	345	329	302	307
	Fuel Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	1,518	1,591	1,673	1,779	1,972	2,170	2,375	2,277	2,176	2,064	1,916	1,780
	Adjustment to opening balance for 06/07 Price adjustment.												
9	Refund/(Collection) Rider	-62	-59	-54	-54	-55	-58	-415	-425	-465	-484	-444	-451
10	Stab. Fund Transfer to GRA Shortfall												
11	Additional Diesel Cost (L7)	129	136	153	240	245	255	308	316	345	329	302	307
12	Fuel Swap												
13	Closing Balance Before Interest (L8 + L9 + L10 + L11 + L12)	1,585	1,667	1,773	1,965	2,162	2,367	2,269	2,168	2,057	1,909	1,774	1,636
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest (Charged) Earned	6	6	6	7	8	8	8	8	7	7	6	6
16	Closing Balance (L13+L15)	1,591	1,673	1,779	1,972	2,170	2,375	2,277	2,176	2,064	1,916	1,780	1,642

Notes:

1. The calculations are based on actual diesel generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.3.3: DIESEL COMMUNITIES STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.		Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	Forecast Diesel Generation (MWh)	3,117	2,964	2,687	2,723	2,777	2,892	3,498	3,584	3,919	4,085	3,743	3,801
2	Approved Efficiency (kWh/L)	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598	3.598
3	Litre of Fuel Required (000 Litre)	866	824	747	757	772	804	972	996	1,089	1,135	1,040	1,056
4	Forecast Diesel Price (weighted average) (\$/L)	1.239	1.239	1.239	1.137	1.137	1.137	1.137	1.137	1.137	1.148	1.148	1.148
5	Approved Diesel Price in Rates (weighted average) (\$/L)	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948	0.948
6	Increase (Decrease) in Fuel Price from Rates (\$) (L4 - L5)	0.291	0.291	0.291	0.189	0.189	0.189	0.189	0.189	0.189	0.200	0.200	0.200
7	Additional Diesel Cost (\$000)	253	240	218	143	146	152	184	188	206	227	208	211
	Fuel Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	1,642	1,529	1,421	1,323	1,145	964	774	543	305	44	-217	-456
	Adjustment to opening balance for 06/07 Price adjustment.												
9	Refund/(Collection) Rider	-371	-353	-320	-324	-331	-345	-417	-427	-467	-487	-446	-453
10	Stab. Fund Transfer to GRA Shortfall												
11	Additional Diesel Cost (L7)	253	240	218	143	146	152	184	188	206	227	208	211
12	Fuel Swap												
13	Closing Balance Before Interest (L8 + L9 + L10 + L11 + L12)	1,523	1,416	1,318	1,141	960	771	541	304	44	-216	-455	-698
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest (Charged) Earned	5	5	5	4	3	3	2	1		1	1	3
16	Closing Balance (L13+L15)	1,529	1,421	1,323	1,145	964	774	543	305	44	-217	-456	-701

Notes:

- The calculations are based on actual diesel generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.4.1: INUVIK RATE STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.		(MWh)	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	actuals	Actual Gas Generation	2,225	2,338	2,033	1,782	2,269	2,247	2,625	2,199	2,303	2,253	2,686	2,813
2	actuals	Actual Diesel Generation	208	72	302	706	140	101	132	624	722	790	204	132
3	actuals	Total Actual Generation	2,433	2,410	2,336	2,487	2,409	2,348	2,757	2,823	3,026	3,042	2,890	2,945
4	per GRA	GRA forecast Gas Generation	2,509	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	3,031	3,001	2,929
		Gas Portion of Load												
5	min line 4, line 5	Expected Generation (MWh)	2,433	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	3,031	2,890	2,929
6	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
7	line 6 / line 7	Expected Gas Fuel Required (000 m ³)	716	669	638	636	642	653	690	759	836	892	850	862
8	per GRA	GRA Gas Price (\$/m ³)	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
9	line 8 * line 9	Approved GRA Fuel Cost (\$000)	308	288	275	273	276	281	296	326	360	384	366	370
10	line 1	Actual Gas Generation (MWh)	2,225	2,338	2,033	1,782	2,269	2,247	2,625	2,199	2,303	2,253	2,686	2,813
11	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
12	line 11 / line 12	Gas Fuel Required (000 m ³)	654	688	598	524	668	661	772	647	678	663	790	828
13	actuals	Actual Gas Price (\$/m ³)	0.473	0.472	0.473	0.476	0.447	0.448	0.447	0.447	0.447	0.447	0.447	0.447
14	line 13 * line 14	Fuel Cost at Gas Price (\$000)	309	324	283	249	299	296	345	289	303	297	353	370
15	line 6 - line 11	Difference in Gas Generation (MWh)	208	65	137	379	86369	27	281	381	540	779	204	116
16	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
17	line 16 / line 17	Diesel Fuel Required (000 litres)	57	-18	38	104	-24	-7	-77	105	148	214	56	32
18	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
19	line 18 * line 19	Fuel Cost at Diesel Price (\$000)	46	-14	30	83	-19	-6	-62	83	118	171	45	25
20	line 15 + line 20	Total Fuel Cost (\$000)	355	310	313	332	280	291	284	373	421	467	398	395
21	line 21 - line 10	Price Variance	47	23	39	59	4	10	-13	46	62	84	32	25
		Diesel Portion of Load												
22	line 2	Actual Diesel Generation (MWh)	208	72	302	706	140	101	132	624	722	790	204	132
23	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
24	line 34 / line 35	Diesel Fuel Required (000 litres)	57	20	83	194	39	28	36	172	199	217	56	36
25														
26	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
27	actuals	Actual Diesel Price (\$/L)	0.939	0.939	0.975	1.056	1.056	1.056	1.056	1.048	1.048	1.048	1.073	1.124
28	line 39 - line 38	Increase (Decrease)	0.142	0.142	0.178	0.259	0.259	0.259	0.259	0.251	0.251	0.251	0.276	0.327
29	line 36 * line 40	Price Variance (\$000)	8	3	15	50	10	7	9	43	50	55	16	12
30	line 22 + line 33 + line 41	Total Variance (\$000)	55	25	53	109	14	17	-3	89	112	138	48	37
31		Inuvik Stabilization Fund Continuity (\$000)												
32		Opening Deficiency (Surplus)	659	535	579	527	520	552	510	431	454	548	709	638
33		Refund/ (Collection) Rider	-114	-124	-81	-122	-98	-91	-145	-141	-89	19	-121	-115
34		Collection Rider reallocated to GRA shortfall												
35		Fuel Swap	-129	72	-71	-63	61	-20						
36		Additional (Less) Fuel Cost	55	25	53	109	14	17	-3	89	112	138	48	37
37		Stab fund Transfer to GRA Shortfall	61	67	44	66	52	49	68	73	69			
38		Closing Balance Before Interest	533	576	524	517	549	507	429	452	546	705	635	559
39		Interest Rate (Prime less 50 points)	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
40		Interest Earned (Charged)	2	3	2	3	3	2	2	2	3	3	3	2
41		Closing Deficiency (Surplus)	535	579	527	520	552	510	431	454	548	709	638	562

Notes:

- The calculations are based on actual diesel and gas generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The fuel prices used are those approved by the Public Utilities Board in the most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$250,000.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.4.2: INUVIK RATE STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.	(MWh)	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	
1	forecasts	Forecast Gas Generation	2,188	2,299	2,000	1,753	2,232	2,210	2,582	2,163	2,266	2,216	2,642	2,767
2	forecasts	Forecast Diesel Generation	205	71	297	694	138	99	130	614	711	777	201	130
3	forecasts	Total Forecast Generation	2,393	2,370	2,298	2,447	2,370	2,309	2,711	2,776	2,976	2,993	2,843	2,896
4	per GRA	GRA forecast Gas Generation	2,509	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	3,031	3,001	2,929
Gas Portion of Load														
5	min line 4, line 5	Expected Generation (MWh)	2,393	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	2,993	2,843	2,896
6	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
7	line 6 / line 7	Expected Gas Fuel Required (000 m ³)	704	669	638	636	642	653	690	759	836	880	836	852
8	per GRA	GRA Gas Price (\$/m ³)	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
9	line 8 * line 9	Approved GRA Fuel Cost (\$000)	303	288	275	273	276	281	296	326	360	379	360	366
10	line 1	Forecast Gas Generation (MWh)	2,188	2,299	2,000	1,753	2,232	2,210	2,582	2,163	2,266	2,216	2,642	2,767
11	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
12	line 11 / line 12	Gas Fuel Required (000 m ³)	644	676	588	516	657	650	760	636	667	652	777	814
13	forecasts	Forecast Gas Price (\$/m ³)	0.445	0.445	0.445	0.563	0.563	0.563	0.563	0.563	0.522	0.522	0.522	0.522
14	line 13 * line 14	Fuel Cost at Gas Price (\$000)	287	301	262	290	370	366	428	358	376	340	405	424
15	line 6 - line 11	Difference in Gas Generation (MWh)	205	26	170	408	49	10	238	417	577	777	201	130
16	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
17	line 16 / line 17	Diesel Fuel Required (000 litres)	56	-7	47	112	-14	3	-65	115	159	214	55	36
18	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
19	line 18 * line 19	Fuel Cost at Diesel Price (\$000)	45	-6	37	90	-11	2	-52	91	127	170	44	28
20	line 15 + line 20	Total Fuel Cost (\$000)	331	295	299	380	359	368	376	450	502	510	449	453
21	line 21 - line 10	Price Variance	29	8	25	107	83	88	79	123	142	132	90	87
Diesel Portion of Load														
22	line 2	Forecast Diesel Generation (MWh)	205	71	297	694	138	99	130	614	711	777	201	130
23	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
24	line 34 / line 35	Diesel Fuel Required (000 litres)	56	19	82	191	38	27	36	169	195	214	55	36
25														
26	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
27	forecasts	Forecast Diesel Price (\$/L)	1.124	1.124	1.124	1.299	1.299	1.299	1.299	1.299	1.299	1.299	1.299	1.299
28	line 39 - line 38	Increase (Decrease)	0.327	0.327	0.327	0.502	0.502	0.502	0.502	0.502	0.502	0.502	0.502	0.502
29	line 36 * line 40	Price Variance (\$000)	18	6	27	96	19	14	18	85	98	107	28	18
30	line 22 + line 33 + line 41	Total Variance (\$000)	47	14	51	203	102	101	97	208	241	239	117	104
31		Inuvik Stabilization Fund Continuity (\$000)												
32		Opening Deficiency (Surplus)	562	571	548	563	728	793	859	772	792	830	866	790
33		Refund/ (Collection) Rider	-40	-39	-38	-41	-39	-38	-187	-191	-205	-206	-196	-200
34		Collection Rider reallocated to GRA shortfall												
35		Fuel Swap												
36		Additional (Less) Fuel Cost	47	14	51	203	102	101	97	208	241	239	117	104
37		Stab fund Transfer to GRA Shortfall												
38		Closing Balance Before Interest	569	546	561	725	791	856	770	789	827	863	787	695
39		Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
40		Interest Earned (Charged)	2	2	2	3	3	3	3	3	3	3	3	3
41		Closing Deficiency (Surplus)	571	548	563	728	793	859	772	792	830	866	790	697

Notes:

- The calculations are based on actual diesel and gas generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$250,000.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.4.3: INUVIK RATE STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line no.			Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	forecasts	Forecast Gas Generation	2,438	2,562	2,229	1,953	2,487	2,463	2,877	2,410	2,525	2,469	2,944	3,083
2	forecasts	Forecast Diesel Generation	228	79	331	773	153	110	145	684	792	865	224	145
3	forecasts	Total Forecast Generation	2,666	2,641	2,560	2,726	2,641	2,574	3,022	3,094	3,317	3,335	3,168	3,228
4	per GRA	GRA forecast Gas Generation	2,509	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	3,031	3,001	2,929
Gas Portion of Load														
5	min line 4, line 5	Expected Generation (MWh)	2,509	2,273	2,170	2,161	2,183	2,220	2,344	2,579	2,843	3,031	3,001	2,929
6	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
7	line 6 / line 7	Expected Gas Fuel Required (000 m ³)	738	669	638	636	642	653	690	759	836	892	883	862
8	per GRA	GRA Gas Price (\$/m ³)	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
9	line 8 * line 9	Approved GRA Fuel Cost (\$000)	317	288	275	273	276	281	296	326	360	384	380	370
10	line 1	Forecast Gas Generation (MWh)	2,438	2,562	2,229	1,953	2,487	2,463	2,877	2,410	2,525	2,469	2,944	3,083
11	per GRA	GRA Gas Efficiency	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399	3.399
12	line 11 / line 12	Gas Fuel Required (000 m ³)	717	754	656	575	732	725	846	709	743	726	866	907
13	forecasts	Forecast Gas Price (\$/m ³)	0.522	0.522	0.522	0.522	0.522	0.522	0.522	0.522	0.522	0.519	0.519	0.519
14	line 13 * line 14	Fuel Cost at Gas Price (\$000)	374	393	342	300	382	378	442	370	387	377	450	471
15	line 6 - line 11	Difference in Gas Generation (MWh)	71	289	59	208	304	243200	533	169	318	562	57	155
16	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
17	line 16 / line 17	Diesel Fuel Required (000 litres)	19	-80	-16	57	-84	-67	-147	47	88	155	16	-43
18	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
19	line 18 * line 19	Fuel Cost at Diesel Price (\$000)	16	-63	-13	46	-67	-53	-117	37	70	123	13	-34
20	line 15 + line 20	Total Fuel Cost (\$000)	390	330	329	345	315	325	325	407	457	500	462	437
21	line 21 - line 10	Price Variance	72	42	55	72	39	44	28	81	98	117	83	67
Diesel Portion of Load														
22	line 2	Forecast Diesel Generation (MWh)	228	79	331	773	153	110	145	684	792	865	224	145
23	per GRA	GRA Diesel Efficiency	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635	3.635
24	line 34 / line 35	Diesel Fuel Required (000 litres)	63	22	91	213	42	30	40	188	218	238	62	40
25														
26	per GRA	GRA Diesel Price (\$/L)	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797	0.797
27	forecasts	Forecast Diesel Price (\$/L)	1.299	1.299	1.299	1.089	1.089	1.089	1.089	1.089	1.089	1.089	1.089	1.089
28	line 39 - line 38	Increase (Decrease)	0.502	0.502	0.502	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
29	line 36 * line 40	Price Variance (\$000)	31	11	46	62	12	9	12	55	64	69	18	12
30	line 22 + line 33 + line 41	Total Variance (\$000)	104	53	100	134	51	53	40	136	161	186	100	78
Inuvik Stabilization Fund Continuity (\$000)														
31		Opening Deficiency (Surplus)	573	494	365	290	236	104	-21	-191	-271	-341	-387	-507
32		Refund/ (Collection) Rider	-185	-183	-177	-189	-183	-178	-209	-214	-230	-231	-219	-223
33		Collection Rider reallocated to GRA shortfall												
34		Fuel Swap												
35		Additional (Less) Fuel Cost	104	53	100	134	51	53	40	136	161	186	100	78
36		Stab fund Transfer to GRA Shortfall												
37		Closing Balance Before Interest	492	364	289	235	104	-21	-191	-270	-340	-385	-506	-653
38		Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
39		Interest Earned (Charged)	2	1	1	1			-1	-1	-1	-1	-2	-2
40		Closing Deficiency (Surplus)	494	365	290	236	104	-21	-191	-271	-341	-387	-507	-655

Notes:

- The calculations are based on actual diesel and gas generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$250,000.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.5.1: NORMAN WELLS RATE STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	Purchased Power (MWh) fr Imperial Oil Inv	734	659	601	707	601	675	769	914	947	979	999	970
2	Purchased Power Price (\$/kWh)	0.292	0.292	0.292	0.268	0.268	0.268	0.288	0.288	0.288	0.322	0.322	0.322
3	GRA Purchased Power Price (\$/kWh)	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279
4	Increase (Decrease) in Price	0.013	0.013	0.013	-0.011	-0.011	-0.011	0.009	0.009	0.009	0.043	0.043	0.043
5	Fuel Price Draw (Contribution) (\$000)	9	8	8	-8	-7	-7	7	8	9	42	43	41
6	Fuel Price Draw (Contribution) YTD (\$000)	9	18	25	18	11	3	10	19	27	69	111	153
7	Norman Wells Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	334	295	313	292	252	253	231	213	233	170	269	291
9	Refund/ (Collection) Rider	-86	-91	-65	-110	-86	-70	-112	-72	-166	46	-22	-23
10	Collection Rider reallocated to GRA shortfall	74	78	56	95	74	60	87	83	93			
11	Fuel Swap Mark to Market	-39	21	-21	-19	18	-6						
12	Additional/ (Less) Purchased Power Cost	9	8	8	-8	-7	-7	7	8	9	42	43	41
13	Diesel Fuel used per Agreement with Town of Norman Wells										11		
14	Closing Balance Before Interest	293	312	291	251	251	230	212	232	169	268	289	309
15	Interest Rate (Prime less 50 points)	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
16	Interest Charged (Earned)	1	1	1	1	1	1	1	1	1	1	1	1
17	Closing Deficiency (Surplus)	295	313	292	252	253	231	213	233	170	269	291	310

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The purchased power prices used are those approved by the Public Utilities Board in the most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$100,000.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.5.2: NORMAN WELLS RATE STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
1	Forecast Purchased Power (MWh) fr Imperial Oil Inv	760	681	622	732	622	698	795	946	979	1,013	1,033	1,003
2	Forecast Purchased Power Price (\$/kWh)	0.322	0.322	0.322	0.440	0.440	0.440	0.440	0.440	0.440	0.366	0.366	0.366
3	GRA Purchased Power Price (\$/kWh)	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279
4	Increase (Decrease) in Price	0.043	0.043	0.043	0.161	0.161	0.161	0.161	0.161	0.161	0.087	0.087	0.087
5	Fuel Price Draw (Contribution) (\$000)	32	29	26	118	100	113	128	153	158	88	89	87
6	Fuel Price Draw (Contribution) YTD (\$000)	32	61	88	206	306	419	547	700	858	946	1,035	1,122
7	Norman Wells Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	310	344	374	402	522	624	740	704	662	618	507	382
9	Refund/ (Collection) Rider							-166	-197	-204	-211	-216	-209
10	Collection Rider reallocated to GRA shortfall												
11	Fuel Swap Mark to Market												
12	Additional/ (Less) Purchased Power Cost	32	29	26	118	100	113	128	153	158	88	89	87
13	Diesel Fuel used per Agreement with Town of Norman Wells										11		
14	Closing Balance Before Interest	342	373	400	520	622	737	702	660	616	505	380	259
15	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
16	Interest Charged (Earned)	1	1	1	2	2	3	3	2	2	2	1	1
17	Closing Deficiency (Surplus)	344	374	402	522	624	740	704	662	618	507	382	260

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast purchased power price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$100,000.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.5.3: NORMAN WELLS RATE STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	Forecast Purchased Power (MWh) fr Imperial Oil Inv	906	812	741	872	741	832	948	1,127	1,167	1,207	1,232	1,196
2	Forecast Purchased Power Price (\$/kWh)	0.366	0.366	0.366	0.366	0.366	0.366	0.366	0.366	0.366	0.363	0.363	0.363
3	GRA Purchased Power Price (\$/kWh)	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279	0.279
4	Increase (Decrease) in Price	0.087	0.087	0.087	0.087	0.087	0.087	0.087	0.087	0.087	0.084	0.084	0.084
5	Fuel Price Draw (Contribution) (\$000)	78	70	64	76	64	72	82	98	101	102	104	101
6	Fuel Price Draw (Contribution) YTD (\$000)	78	149	213	289	353	425	507	605	706	808	912	1,012
7	Norman Wells Stabilization Fund Continuity (\$000)												
8	Opening Deficiency (Surplus)	260	150	52	-38	-145	-235	-337	-454	-593	-737	-879	-1,035
9	Refund/ (Collection) Rider	-188	-169	-154	-181	-154	-173	-197	-235	-243	-251	-256	-249
10	Collection Rider reallocated to GRA shortfall												
11	Fuel Swap Mark to Market												
12	Additional/ (Less) Purchased Power Cost	78	70	64	76	64	72	82	98	101	102	104	101
13	Diesel Fuel used per Agreement with Town of Norman Wells										11		
14	Closing Balance Before Interest	150	52	-38	-144	-234	-336	-452	-591	-735	-876	-1,032	-1,183
15	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
16	Interest Charged (Earned)	1			-1	-1	-1	-2	-2	-3	-3	-3	-4
17	Closing Deficiency (Surplus)	150	52	-38	-145	-235	-337	-454	-593	-737	-879	-1,035	-1,187

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast purchased power price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$100,000.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

Friday, August 15, 2008

**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.6.1: Fort Smith Fuel STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE**

Line No.		Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	Actual Price Diesel (\$/L)	0.766	0.766	0.804	0.782	0.782	0.756	0.756	0.932	0.932	0.932	0.932	0.930
2	GRA Fuel Price (\$/L)	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793
3	Increase (Decrease)	(0.027)	(0.027)	0.011	(0.011)	(0.011)	(0.037)	(0.037)	0.139	0.139	0.139	0.139	0.137
4	Diesel Generation (MWh)	2	3	103	1		846	2	2	4		33	
5	Ft Smith Plant Efficiency	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277
6	Fuel Req'd - Litres (000)	1	1	31			258	1		1		10	
7	Fuel Price Draw (Contribution)						-10					1	
8	FT Smith Fuel Stabilization Fund Continuity (\$000)												
9	Opening Deficiency (Surplus)	37	34	31	29	26	24	12	9	6	2	3	2
10	Refund/ (Collection) Rider	-11	-10	-10	-11	-9	-9	-12	-11	-15	1	-2	
11	Collection Rider reallocated to GRA shortfall	8	8	7	8	6	7	9	9	10			
12	Additional/ (Less) Diesel Cost						-10					1	
13	Closing Balance Before Interest	34	31	29	26	24	12	8	6	2	3	2	2
14	Interest Rate (Prime less 50 points)	5.25%	5.25%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
15	Interest Charged (Earned)												
16	Closing Deficiency (Surplus)	34	31	29	26	24	12	9	6	2	3	2	2

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The fuel prices used are those approved by the Public Utilities Board in the most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.6.2: Fort Smith Fuel STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
1	Forecast Price Diesel (\$/L)	0.930	0.930	0.930	1.145	1.145	1.145	1.145	1.145	1.145	1.145	1.145	1.145
2	GRA Fuel Price (\$/L)	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793
3	Increase (Decrease)	0.137	0.137	0.137	0.352	0.352	0.352	0.352	0.352	0.352	0.352	0.352	0.352
4	Forecast Generation (MWh)	1	2	52			425	1	1	2		17	
5	Ft Smith Plant Efficiency	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277
6	Fuel Req'd - Litres (000)			16			130			1		5	
7	Fuel Price Draw (Contribution)			2			46					2	
8	FT Smith Fuel Stabilization Fund Continuity (\$000)												
9	Opening Deficiency (Surplus)	2	2	2	4	4	4	50	48	46	43	39	39
10	Refund/ (Collection) Rider							-3	-3	-3	-3	-3	-3
11	Collection Rider reallocated to GRA shortfall												
12	Additional/ (Less) Diesel Cost			2			46					2	
13	Closing Balance Before Interest	2	2	4	4	4	50	48	45	43	39	38	36
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest Charged (Earned)												
16	Closing Deficiency (Surplus)	2	2	4	4	4	50	48	46	43	39	39	36

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.6.3: Fort Smith Fuel STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	Forecast Price Diesel (\$/L)	1.145	1.145	1.145	1.037	1.037	1.037	1.037	1.037	1.037	1.037	1.037	1.037
2	GRA Fuel Price (\$/L)	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793	0.793
3	Increase (Decrease)	0.352	0.352	0.352	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
4	Forecast Generation (MWh)	1	2	52			425	1	1	2		17	
5	Ft Smith Plant Efficiency	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277	3.277
6	Fuel Req'd - Litres (000)			16			130			1		5	
7	Fuel Price Draw (Contribution)			6			32					1	
8	FT Smith Fuel Stabilization Fund Continuity (\$000)												
9	Opening Deficiency (Surplus)	36	33	31	35	33	30	60	58	55	52	48	47
10	Refund/ (Collection) Rider	-3	-2	-2	-2	-2	-2	-3	-3	-3	-4	-3	-3
11	Collection Rider reallocated to GRA shortfall												
12	Additional/ (Less) Diesel Cost			6			32					1	
13	Closing Balance Before Interest	33	31	35	32	30	60	57	55	52	48	47	44
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest Charged (Earned)												
16	Closing Deficiency (Surplus)	33	31	35	33	30	60	58	55	52	48	47	44

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.7.1: Yellowknife Fuel STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	Actual Price Diesel (\$/L)	0.825	0.782	0.780	0.780	0.780	0.780	0.964	1.000	1.000	1.000	0.989	1.071
2	GRA Fuel Price (\$/L)	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
3	Increase (Decrease)	0.068	0.025	0.023	0.023	0.023	0.023	0.207	0.243	0.243	0.243	0.232	0.314
4	Power Corporation Diesel Generation												
5	Actual Diesel Generation MWh	34	562	262	461	60	138	3,892	3,882	2,662	1,163	3,868	183
6	YK Plant Efficiency	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
7	Fuel Req'd - Litres (000)	10	160	75	132	17	39	1,112	1,109	761	332	1,105	52
8	Fuel Price Draw (Contribution) (\$000)	1	4	2	3		1	230	270	185	81	256	16
9	YK Fuel Stabilization Fund Continuity (\$000)												
10	Opening Deficiency (Surplus)	5	5	9	11	14	15	16	247	519	707	790	1,051
11	Refund/ (Collection) Rider												1
12	Additional/ (Less) Diesel Cost	1	4	2	3		1	230	270	185	81	256	16
13	Closing Balance Before Interest	5	9	11	14	15	16	246	516	703	787	1,047	1,068
14	Interest Rate (Prime less 50 points)	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
15	Interest Charged (Earned)							1	2	3	3	4	4
16	Closing Deficiency (Surplus)	5	9	11	14	15	16	247	519	707	790	1,051	1,073

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The fuel prices used are those approved by the Public Utilities Board in the most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.7.2: Yellowknife Fuel STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE

Line No.		Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
1	Forecast Price Diesel (\$/L)	1.071	1.071	1.022	1.111	1.111	1.111	1.111	1.111	1.111	1.111	1.111	1.111
2	GRA Fuel Price (\$/L)	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
3	Increase (Decrease)	0.314	0.314	0.265	0.354	0.354	0.354	0.354	0.354	0.354	0.354	0.354	0.354
4	Power Corporation Diesel Generation												
5	Forecast Diesel Generation (MWh)	50	50	10	1,450	969	161	1,251	2,428	1,404	1,383	2,561	838
6	YK Plant Efficiency	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
7	Fuel Req'd - Litres (000)	14	14	3	414	277	46	357	694	401	395	732	239
8	Fuel Price Draw (Contribution) (\$000)	4	4	1	147	98	16	126	245	142	140	259	85
9	YK Fuel Stabilization Fund Continuity (\$000)	dswe											
10	Opening Deficiency (Surplus)	1,073	1,081	1,089	1,094	1,245	1,348	1,369	1,429	1,604	1,669	1,732	1,914
11	Refund/ (Collection) Rider							-71	-76	-83	-84	-83	-77
12	Additional/ (Less) Diesel Cost	4	4	1	147	98	16	126	245	142	140	259	85
13	Closing Balance Before Interest	1,077	1,085	1,090	1,241	1,343	1,364	1,424	1,599	1,663	1,726	1,908	1,922
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest Charged (Earned)	4	4	4	4	5	5	5	6	6	6	6	7
16	Closing Deficiency (Surplus)	1,081	1,089	1,094	1,245	1,348	1,369	1,429	1,604	1,669	1,732	1,914	1,929

Notes:

- The calculations are based on actual diesel and gas generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

Friday, August 15, 2008

**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.7.3: Yellowknife Fuel STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE**

Line No.		Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	Forecast Price Diesel (\$/L)	1.111	1.111	1.111	1.001	1.001	1.001	1.001	1.001	1.001	1.001	1.001	1.001
2	GRA Fuel Price (\$/L)	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
3	Increase (Decrease)	0.354	0.354	0.354	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
4	Power Corporation Diesel Generation												
5	Forecast Diesel Generation (MWh)	3	42	20	35	4	10	292	292	200	87	291	14
6	YK Plant Efficiency	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
7	Fuel Req'd - Litres (000)	1	12	6	10	1	3	84	83	57	25	83	4
8	Fuel Price Draw (Contribution) (\$000)		4	2	2		1	20	20	14	6	20	1
9	YK Fuel Stabilization Fund Continuity (\$000)												
10	Opening Deficiency (Surplus)	1,929	1,865	1,805	1,755	1,694	1,624	1,554	1,501	1,447	1,385	1,315	1,264
11	Refund/ (Collection) Rider	-71	-71	-58	-69	-76	-76	-79	-80	-81	-81	-76	-79
12	Additional/ (Less) Diesel Cost		4	2	2		1	20	20	14	6	20	1
13	Closing Balance Before Interest	1,858	1,798	1,749	1,688	1,618	1,549	1,496	1,442	1,380	1,311	1,260	1,186
14	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
15	Interest Charged (Earned)	6	6	6	6	6	5	5	5	5	5	4	4
16	Closing Deficiency (Surplus)	1,865	1,805	1,755	1,694	1,624	1,554	1,501	1,447	1,385	1,315	1,264	1,190

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$1 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.8.1: WATER STABILIZATION FUND - 2007/08
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE
SNARE-YELLOWKNIFE ZONE

Line No.	Generation (MWh)	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
1	Hydro Generation In Rates	17,439	17,376	15,131	16,393	18,316	18,495	19,358	19,803	19,969	20,088	18,546	19,086
2	Actual Hydro Generation	16,113	15,197	14,311	16,279	15,757	14,785	13,178	13,716	16,317	18,955	14,776	18,066
3	Generation Required (Saved)	1,326	2,179	820	114	2,559	3,710	6,180	6,087	3,652	1,133	3,770	1,021
4	Transmission Line Losses (L3 x 4%)	-53	-87	-33	-5	-102	-148	-247	-243	-146	-45	-151	-41
5	A - Diesel Gen. Req'd (Saved) (L3+L4)	1,272	2,092	788	109	2,457	3,561	5,933	5,844	3,506	1,088	3,619	980
6	B - Actual Diesel Generation	34	562	262	461	60	138	3,892	3,882	2,662	1,163	3,868	183
7	Lessor of A or B	34	562	262	109	60	138	3,892	3,882	2,662	1,088	3,619	183
8	Diesel Plant Efficiency(kWh/L)	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
9	Litres of Fuel Required (L7/L8) (000)	10	160	75	31	17	39	1,112	1,109	761	311	1,034	52
10	GRA Diesel Fuel Price \$	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
11	Additional (Less) Diesel Cost \$000 (L9 x L10)	7	121	57	24	13	30	842	840	576	235	783	40
12	Water Stabilization Fund Continuity (\$000)												
13	Opening Deficiency (Surplus)	324	333	457	516	542	557	590	1,439	2,289	2,878	3,127	3,926
14	Refund/ (Collection) Rider												
15	Additional (Less) Diesel Cost (L11)	7	121	57	24	13	30	842	840	576	235	783	40
16	Closing Balance Before Interest	332	454	513	539	555	587	1,432	2,278	2,865	3,114	3,910	3,966
17	Interest Rate (Prime less 50 points)	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%	5.25%	5.25%	4.75%
18	Interest Charged (Earned)	1	2	2	3	3	3	7	11	13	14	16	16
19	Closing Deficiency (Surplus)	333	457	516	542	557	590	1,439	2,289	2,878	3,127	3,926	3,982

Notes:

- The calculations are based on actual diesel and gas generation.
- The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
- The fuel prices used are those approved by the Public Utilities Board in the most recent GRA.
- The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
- A rider will be applied or refunded in order to remain within the fund range of +/- \$3 million.
- This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.8.2: WATER STABILIZATION FUND - Forecast 2008/09
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE
SNARE-YELLOWKNIFE ZONE

Line No.	Generation (MWh)	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
1	Hydro Generation In Rates	17,439	17,376	15,131	16,393	18,316	18,495	19,358	19,803	19,969	20,088	18,546	19,086
2	Forecast Hydro Generation	15,680	14,330	12,950	13,940	14,120	14,080	15,900	15,970	18,330	18,830	17,360	17,940
3	Generation Required (Saved)	1,759	3,046	2,181	2,453	4,196	4,415	3,458	3,833	1,639	1,258	1,186	1,146
4	Transmission Line Losses (L3 x 4%)	-70	-122	-87	-98	-168	-177	-138	-153	-66	-50	-47	-46
5	A - Diesel Gen. Req'd (Saved) (L3+L4)	1,688	2,924	2,094	2,355	4,028	4,238	3,320	3,680	1,573	1,208	1,138	1,100
6	B - Forecast Diesel Generation	50	50	10	1,450	969	161	1,251	2,428	1,404	1,383	2,561	838
7	Lessor of A or B	50	50	10	1,450	969	161	1,251	2,428	1,404	1,208	1,138	838
8	Diesel Plant Efficiency(kWh/L)	3.5000	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
9	Litres of Fuel Required (L7/L8) (000)	14	14	3	414	277	46	357	694	401	345	325	239
10	GRA Diesel Fuel Price \$	0.7570	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
11	Additional (Less) Diesel Cost \$000 (L9 x L10)	11	11	2	314	210	35	270	525	304	261	246	181
12	Water Stabilization Fund Continuity (\$000)												
13	Opening Deficiency (Surplus)	3,982	4,007	4,032	4,048	4,377	4,604	4,654	4,857	5,308	5,532	5,713	5,878
14	Refund/ (Collection) Rider							-86	-92	-100	-101	-100	-93
15	Additional (Less) Diesel Cost (L11)	11	11	2	314	210	35	270	525	304	261	246	181
16	Closing Balance Before Interest	3,993	4,017	4,034	4,362	4,587	4,638	4,839	5,290	5,512	5,692	5,859	5,966
17	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
18	Interest Charged (Earned)	14	14	14	16	17	16	17	18	20	21	19	22
19	Closing Deficiency (Surplus)	4,007	4,032	4,048	4,377	4,604	4,654	4,857	5,308	5,532	5,713	5,878	5,988

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$3 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

Friday, August 15, 2008

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule C.8.3: WATER STABILIZATION FUND - Forecast 2009/10
USING THE GRA APPROVAL FOR EFFICIENCY AND FUEL PRICE
SNARE-YELLOWKNIFE ZONE

Line No.	Generation (MWh)	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
1	Hydro Generation In Rates	17,439	17,376	15,131	16,393	18,316	18,495	19,358	19,803	19,969	20,088	18,546	19,086
2	Forecast Hydro Generation	18,137	17,106	16,109	18,324	17,736	16,643	14,833	15,439	18,367	21,336	16,632	20,335
3	Generation Required (Saved)	-699	270	-977	-1,931	580	1,852	4,525	4,364	1,602	-1,248	1,914	-1,249
4	Transmission Line Losses (L3 x 4%)	28	-11	39	77	-23	-74	-181	-175	-64	50	-77	50
5	A - Diesel Gen. Req'd (Saved) (L3+L4)	-671	259	-938	-1,854	557	1,778	4,344	4,190	1,538	-1,198	1,837	-1,199
6	B - Forecast Diesel Generation	3	42	20	35	4	10	292	292	200	87	291	14
7	Lessor of A or B	-671	42	-938	-1,854	4	10	292	292	200	-1,198	291	-1,199
8	Diesel Plant Efficiency(kWh/L)	3.5000	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500	3.500
9	Litres of Fuel Required (L7/L8) (000)	-192	12	-268	-530	1	3	84	83	57	-342	83	-343
10	GRA Diesel Fuel Price \$	0.7570	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
11	Additional (Less) Diesel Cost \$000 (L9 x L10)	-145	9	-203	-401	1	2	63	63	43	-259	63	-259
12	Water Stabilization Fund Continuity (\$000)												
13	Opening Deficiency (Surplus)	5,988	5,777	5,721	5,467	5,001	4,927	4,854	4,840	4,823	4,786	4,445	4,431
14	Refund/ (Collection) Rider	-86	-86	-70	-83	-92	-92	-95	-96	-97	-97	-92	-95
15	Additional (Less) Diesel Cost (L11)	-145	9	-203	-401	1	2	63	63	43	-259	63	-259
16	Closing Balance Before Interest	5,757	5,701	5,448	4,983	4,909	4,837	4,822	4,806	4,769	4,429	4,416	4,076
17	Interest Rate (Prime less 50 points)	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
18	Interest Charged (Earned)	20	21	19	18	18	17	17	17	17	16	14	15
19	Closing Deficiency (Surplus)	5,777	5,721	5,467	5,001	4,927	4,854	4,840	4,823	4,786	4,445	4,431	4,091

Notes:

1. The calculations are based on actual diesel and gas generation.
2. The efficiency rates used are those approved by the Public Utilities Board in the most recent GRA.
3. The forecast fuel price is based on the best information available and the consistent method approved by most recent GRA.
4. The interest rate used is equal to the Prime Rate in effect at the Corporation's bank at each month end, less 50 basis points, applied to the month end balance in the funds.
5. A rider will be applied or refunded in order to remain within the fund range of +/- \$3 million.
6. This table is for illustrative purposes only. Balances in the fund will reflect actual fuel prices, generation and rider collections.

**Appendix C.1
Fuel Price Estimates
2008/09 Excluded Communities**

NYMEX price per gallon for diesel June/2008 **139.96** per barrel crude oil in USD dollars
 there are 42 US gallons to a barrel **3.3324** per US gallon crude oil in US dollars
 there are 3.782413 liters per US gallon **0.8810** per liter crude oil in US dollars
 US dollar conversion rate is 1.0121 **0.8917** per liter crude oil in Canadian dollars
 (NYMEX as of 2:15pm 6/26/2008. Exchange Rate as of noon 6/26/2008)

Price per liter of Crude in Canadian dollars **0.8917**
 Estimated Spread between crude oil and LS diesel (Edmonton Rack) **0.1200**
1.0117

	Product	Freight	Fuel Tax	Total	
	Yellowknife	1.0117	0.0681	0.0310	1.1108
	Behchoko	1.0117	0.0893	0.0310	1.1320
	Fort Smith	1.0117	0.1027	0.0310	1.1454 Summer
	Fort Resolution	1.0117	0.1717	0.0310	1.2143 Summer
	Norman Wells	1.0117	0.1560	0.0310	1.1986 Summer
	Fort McPherson	1.0117	0.2432	0.0310	1.2859 Throughout the year from Inuvik
	Aklavik	1.0117	0.2315	0.0310	1.2742 Throughout the year from Inuvik

Freight was inflated by 3% over 2007 excluded.

Note:

1. The change in the volume shipped to Inuvik will not affect the shipping rate for nearby communities. Re
2. Shipping rates for NTCL from previous year to come from Brenda Larson as per March 30 email from Rod.

Appendix C.2
Fuel Price Estimates
Summer of 2008

- Price Taken from PPD forecast

	Product	Freight	Markup	Fuel Tax	Total
Lutsel K'e	1.1000	0.1242	0.1266	0.0310	1.4384
Tulita	1.1000	0.1334	0.0766	0.0310	1.3476
Fort Good Hope	1.1000	0.1610	0.0766	0.0310	1.3752
Inuvik	1.1000	0.0850	0.0766	0.0310	1.2992
Tuktoyaktuk	1.1000	0.0850	0.0766	0.0310	1.2992
Sachs Harbour	1.1000	0.0850	0.0901	0.0310	1.3262
Paulatuk	1.1000	0.0850	0.1416	0.0310	1.4292
Ulukhatok	1.1000	0.0850	0.0866	0.0310	1.3192

Disclaimer

These estimates are subject to extreme market place volatility and are not presented as a price commitment. These figures are provided for analysis and planning purposes only.

**Appendix C.3
Fuel Price Estimates
Winter Resupply
For 2008**

NYMEX price per gallon for diesel December/2008 **122.39** per barrel crude oil in USD dollars
 there are 42 US gallons to a barrel **2.9140** per US gallon crude oil in US dollars
 there are 3.782413 liters per US gallon **0.7704** per liter crude oil in US dollars
 US dollar conversion rate is 1.0121 **0.7797** per liter crude oil in Canadian dollars
 (NYMEX as of 8/5/2008. Exchange Rate as of noon 6/26/2008)

Price per liter of Crude in Canadian dollars **0.7797**
 Estimated Spread between crude oil and LS diesel (Edmonton Rack) **0.1200**
0.8997

	Product	Freight	Markup	Fuel Tax	Total
Wrigley	0.8997	0.1166	0.0700	0.0310	1.1174
Wha Ti	0.8997	0.1293	0.0700	0.0310	1.1301
Gameti	0.8997	0.1612	0.0700	0.0310	1.1619
Colville Lake	0.8997	0.4158	0.0700	0.0310	1.4165
Fort Good Hope	0.8997	0.3171	0.0700	0.0310	1.3179
Deline	0.8997	0.2535	0.0700	0.0310	1.2542
Jean Marie River	0.8997	0.0889	0.0700	0.0310	1.0896
Tsiighehtchic	0.8997	0.2220	0.0700	0.0310	1.2228
Fort Simpson	0.8997	0.0923	0.0700	0.0310	1.0930
Fort Liard	0.8997	0.1088	0.0700	0.0310	1.1096
Nahanni Butte	0.8997	0.1088	0.0700	0.0310	1.1096

Freight was inflated by 3% over 2007 winter.

Disclaimer

These estimates are subject to extreme market place volatility and are not presented as a price commitment.
 These figures are provided for analysis and planning purposes only.

Appendix C.4
Fuel Price Estimates
2008/09 Excluded Communities

NYMEX price per gallon for diese June/2009 **122.44** per barrel crude oil in USD dollars
there are 42 US gallons to a barre **2.9152** per US gallon crude oil in US dollars
there are 3.782413 liters per US gallon **0.7707** per liter crude oil in US dollars
US dollar conversion rate is 1.0121 **0.7801** per liter crude oil in Canadian dollars
(NYMEX as of 8/5/2008. Exchange Rate as of noon 6/26/2008)

Price per liter of Crude in Canadian dollars **0.7801**
Estimated Spread between crude oil and LS diesel (Edmonton Rack) **0.1200**
0.9001

	Product	Freight	Fuel Tax	Total	
Yellowknife	0.9001	0.0701	0.0310	1.0012	When is the community supplied. Need to know this to determine the appropriate NYMEX future
Behchoko	0.9001	0.0920	0.0310	1.0230	
Fort Smith	0.9001	0.1058	0.0310	1.0368	
Fort Resolution	0.9001	0.1768	0.0310	1.1079	
Norman Wells	0.9001	0.1606	0.0310	1.0917	
Fort McPherson	0.9001	0.2505	0.0310	1.1816	
Aklavik	0.9001	0.2385	0.0310	1.1695	

Freight was inflated by 3% over 2008 excluded

**Appendix C.5
Fuel Price Estimates
Summer of 2009**

NYMEX price per gallon for diesel June/2009 **122.44** per barrel crude oil in USD dollars
 there are 42 US gallons to a barrel **2.9152** per US gallon crude oil in US dollars
 there are 3.782413 liters per US gallon **0.7707** per liter crude oil in US dollars
 US dollar conversion rate is 1.0121 **0.7801** per liter crude oil in Canadian dollars
 (NYMEX as of 8/5/2008. Exchange Rate as of noon 6/26/2008)

Price per liter of Crude in Canadian dollars **0.7801**
 Estimated Spread between crude oil and LS diesel (Edmonton Rack) **0.1200**
0.9001

	Product	Freight	Markup	Fuel Tax	Total	
	Lutsel K'e	0.9001	0.1279	0.0700	0.0310	1.1290
	Tulita	0.9001	0.1374	0.0700	0.0310	1.1385
	Fort Good Hope	0.9001	0.1658	0.0700	0.0310	1.1669
	Inuvik	0.9001	0.0876	0.0700	0.0310	1.0886
	Tuktoyaktuk	0.9001	0.0876	0.0700	0.0310	1.0886
	Sachs Harbour	0.9001	0.0876	0.0700	0.0310	1.0886
	Paulatuk	0.9001	0.0876	0.0700	0.0310	1.0886
	Ulukhaktok	0.9001	0.0876	0.0700	0.0310	1.0886

Freight was inflated by 3% over 2008 summer barge.

Disclaimer

These estimates are subject to extreme market place volatility and are not presented as a price commitment. These figures are provided for analysis and planning purposes only.

**Appendix C.6
Fuel Price Estimates
Winter Resupply
For 2009**

NYMEX price per gallon for diesel December/2009 **121.41** per barrel crude oil in USD dollars
 there are 42 US gallons to a barrel **2.8907** per US gallon crude oil in US dollars
 there are 3.782413 liters per US gallon **0.7643** per liter crude oil in US dollars
 US dollar conversion rate is 1.0121 **0.7735** per liter crude oil in Canadian dollars
 (NYMEX as of 8/5/2008. Exchange Rate as of noon 6/26/2008)

Price per liter of Crude in Canadian dollars **0.7735**
 Estimated Spread between crude oil and LS diesel (Edmonton Rack) **0.1200**
0.8935

	Product	Freight	Markup	Fuel Tax	Total
Wrigley	0.8935	0.1201	0.0700	0.0310	1.1146
Wha Ti	0.8935	0.1332	0.0700	0.0310	1.1277
Gameti	0.8935	0.1660	0.0700	0.0310	1.1605
Colville Lake	0.8935	0.4283	0.0700	0.0310	1.4228
Fort Good Hope	0.8935	0.3266	0.0700	0.0310	1.3211
Deline	0.8935	0.2611	0.0700	0.0310	1.2556
Jean Marie River	0.8935	0.0915	0.0700	0.0310	1.0860
Tsiigehtchic	0.8935	0.2287	0.0700	0.0310	1.2232
Fort Simpson	0.8935	0.0951	0.0700	0.0310	1.0896
Fort Liard	0.8935	0.1121	0.0700	0.0310	1.1066
Nahanni Butte	0.8935	0.1121	0.0700	0.0310	1.1066

Freight was inflated by 3% over 2008 winter.

Disclaimer

These estimates are subject to extreme market place volatility and are not presented as a price commitment. These figures are provided for analysis and planning purposes only.

NTPC 2006/07 and 2007/08 GRA Rate Finalization Application
Appendix C.7: Fuel Price Forecast Summary

Diesel Communities

Plant No.	Community	Actual Prices				Forecast Prices								
		Price at Apr. 1, 2008	Price at May 1, 2008	Estimated May 2008 Fuel Required	Price at June 1, 2008	Estimated June 2008 Fuel Required	July 1, 2008 Price Forecast	Estimated July 2008 Fuel Required	Jan 1, 2009 Price Forecast	Estimated Jan 2009 Fuel Required	July 1, 2009 Price Forecast	Estimated July 2009 Fuel Required	Jan 1, 2010 Price Forecast	Estimated Jan 2010 Fuel Required
104	Wha Ti	0.954	1.218	32,365	1.218	29,391	1.218	29,775	1.130	44,377	1.130	30,040	1.128	44,775
105	Gameti	1.030	1.030	20,616	1.211	18,865	1.211	19,091	1.162	27,690	1.162	18,848	1.161	27,327
110	Lutzel K'e	0.989	0.989	31,728	0.989	28,959	1.438	29,316	1.438	42,915	1.129	30,416	1.129	44,565
205	Fort Simpson	1.059	1.059	161,919	1.123	147,081	1.123	148,993	1.093	221,863	1.093	150,372	1.090	224,197
206	Fort Liard	1.081	1.081	47,718	1.253	43,299	1.253	43,869	1.110	65,567	1.110	39,645	1.107	59,262
207	Wrigley	1.004	1.217	13,954	1.217	12,684	1.217	12,848	1.117	19,085	1.117	11,227	1.115	16,692
208	Nahanni Butte	1.112	1.223	12,185	1.223	11,114	1.223	11,252	1.110	16,510	1.110	10,469	1.107	15,392
209	Jean Marie River	1.010	1.010	8,198	1.145	7,489	1.145	7,580	1.090	11,064	1.090	7,332	1.086	10,740
305	Tuktoyaktuk	1.027	1.027	84,148	1.027	76,749	1.299	77,703	1.299	114,040	1.089	77,180	1.089	113,267
306	Fort McPherson	1.242	1.242	66,836	1.350	60,971	1.286	61,727	1.286	90,527	1.182	60,090	1.182	88,047
307	Aklavik	1.252	1.252	61,680	1.252	56,204	1.274	56,910	1.274	83,802	1.170	58,201	1.170	85,735
308	Deline	1.176	1.176	56,661	1.270	51,486	1.270	52,153	1.254	77,566	1.254	51,950	1.256	77,259
309	Fort Good Hope	1.003	1.042	58,496	1.042	53,238	1.375	53,915	1.318	79,737	1.167	58,386	1.321	86,359
310	Tulit'a	0.972	0.972	50,518	0.972	46,079	1.348	46,652	1.348	68,448	1.138	49,255	1.138	72,346
311	Paulatuk	1.188	1.188	31,191	1.142	28,390	1.429	28,751	1.429	42,506	1.089	30,824	1.089	45,615
312	Sachs Harbour	1.132	1.132	21,570	1.146	19,799	1.326	20,027	1.326	28,727	1.089	18,556	1.089	26,507
313	Tsiigehtchic	1.269	1.269	16,142	1.213	14,742	1.213	14,922	1.223	21,799	1.223	14,668	1.223	21,413
314	Colville Lake	1.237	1.309	8,716	1.309	7,909	1.309	8,013	1.417	11,974	1.417	9,185	1.423	13,729
315	Ulukhaktok	1.154	1.154	40,305	1.149	36,680	1.319	37,147	1.319	54,950	1.089	37,067	1.089	54,828
	Weighted Average	1.097	1.113		1.154		1.266		1.239		1.137		1.148	

Other Communities

Plant No.	Community	Actual Prices			Forecast Prices			
		Price at Apr. 1, 2008	Price at May 1, 2008	Price at June 1, 2008	July 1, 2008 Price Forecast	Jan 1, 2009 Price Forecast	July 1, 2009 Price Forecast	Jan 1, 2010 Price Forecast
101	Yellowknife	1.071		1.0215	1.1108		1.0012	
201	Fort Smith	0.930			1.1454		1.0368	
301	Inuvik	1.124			1.2992		1.0886	

- Notes:
1. Actual prices based on latest actual price.
2. July 1, 2008 forecast, Summer resupply communities based on prices provided by PPD, other communities based on NYMEX forecast. Jan 1, 2009, July 1, 2009 and Jan 1, 2010 price forecasts based on NYMEX (Appendix A.1-A.6)

1 **APPENDIX D: STAND-BY RATE PROPOSAL**

2 In Decision 3-2003 (NTPC 2001/03 Phase II GRA) - Directive 8, the Board directed the
3 Corporation to file the results of a study assessing the cost of providing standby service
4 together with proposed standby service agreement including proposals for interconnection
5 standards, subscription periods, exit fees and re-subscription fees.

6
7 Subsequent to the issuance of Decision 3-2003, representatives from NTPC participated in
8 a meeting with representatives from the NWT PUB, NUL-YK, NUL-NWT and the GNWT in
9 June 2004 to discuss issues related to distributed energy (DE) in general, including stand-by
10 rates for DE customers. Following this stakeholder meeting, the NWT PUB commissioned a
11 background paper on DE in the NWT. The background paper was released in January
12 2005.¹⁸

13
14 The DE background paper discusses a broad range of DE applications, however those that
15 are currently practical for application in the NWT can generally be described as belonging to
16 one of two types:

- 17
- 18 • **Small scale Distributed Energy applications to displace some electricity**
19 **consumption.** These would include residential photovoltaic installations and other
20 small scale projects. Generally speaking these types of generation sources would be
21 used to displace some energy consumption, but the individual customer would still

1 purchase a material portion of their energy from the Corporation. These types of
2 projects could be undertaken in all of the communities served by NTPC and would be
3 most attractive in communities served by the highest cost diesel generation. It is not
4 anticipated that customers installing these types of applications would require stand-
5 by service. For customers installing alternative energy applications up to 5kW, the
6 Corporation will not charge stand-by rates to back-up these generation sources. This
7 will allow customers to pursue small scale alternative energy installations and capture
8 any environmental or economic benefits associated with these installations.

- 9
- 10 • **Larger scale Distributed Energy applications to displace most electricity**
11 **consumption.** These projects would include natural gas and diesel generators for
12 combined heat & power (CHP) applications. These projects would generally be
13 undertaken to displace some or all of a customer's electricity consumption, except
14 during periods of maintenance or emergencies. At present these types of projects
15 would generally only be undertaken by customers with the ability to capture and use
16 the heat as well as electricity generated by these technologies. It is anticipated that
17 these types of customers are the ones who would be interested in stand-by service.
18 For customers installing applications larger than 5kW the Corporation proposes to
19 charge a stand-by rate for providing stand-by service.

¹⁸ Distributed Energy in the NWT Background Paper. 2005 Terriplan Consultants. Yellowknife.

1 With respect to purchases of generation from DE applications, the Corporation's current
2 policy is to consider purchases of such generation, where they are surplus to the customer's
3 own use requirements, at prices up to the Corporation's avoided cost. The Corporation is
4 *ntd insert stuff about letter*.

5
6 NTPC completed a study into the principles of stand-by rate design, stand-by rates offered
7 by other major Canadian electric utilities, and interconnection standards. The results of this
8 study and proposed rate design criteria were originally presented in the Corporation's
9 2006/07 & 2007/08 Phase I General Rate Application.¹⁹ Following comments from the Board
10 and intervenors at the Phase I Technical Workshop, the Corporation withdrew the proposed
11 Stand-by Rate Design criteria as the topic was better addressed concurrent with other
12 Phase II matters²⁰. In this application the Corporation is providing a summary of the material
13 previously provided in the 2006/07 and 2007/08 Phase I Application as well as a revised
14 proposal for Retail Stand-by rates. The rate design considerations and proposals are
15 intended at this time to apply only to the second category of DE installations described
16 above. In all cases, the purpose of the stand-by rates is twofold:

- 17
- 18 • To provide customers with clear knowledge of the frameworks and rates that will
19 apply to their service should they seek to be supplied stand-by power from
20 NTPC; and

21

¹⁹ Pages 6-6 through 6-18 of the Corporation's 2006/07 and 2007/08 Phase I General Rate Application.

²⁰ Letter from NTPC to the Board dated February 20, 2007.

- 1 • To protect other customers from the negative impacts on NTPC's revenue
2 requirement that will arise should a General Service customer install their own
3 generation and use NTPC as their source for stand-by under the existing General
4 Service rate schedule. These negative impacts reflect the fact that a standby service
5 customer, if served under the traditional General Service rate will substantially
6 underpay the full costs to serve them and consequently impose a burden on all other
7 customers in the community to cover the stand-by customer's share of the NTPC
8 fixed costs.

9

10 **Stand-by Rates for Other Canadian Utilities**

11 As a starting point, the Corporation conducted a survey of stand-by rate offerings for other
12 utilities in Canada. It is important to note that this survey was undertaken largely for
13 background information purposes as it is recognized that there are key differences between
14 NTPC and these southern jurisdictions, including the size of the systems and the isolated
15 nature of NTPC's electricity systems. Table D.1 summarises stand-by rates, where
16 available, for other major Canadian utilities, with detailed descriptions following.

17

1 **Table D.1 – Summary of Stand-by Rates of Major Canadian Utilities**

Utility	Stand-by Rate Structure	Otherwise Applicable Firm Rate
B.C. Hydro (note 1)	No stand-by rate available	n/a
SaskPower (note 2)	No stand-by rate available	n/a
Hydro Quebec (note 3)	Rate LD	Rate L
Demand (per kW)	\$4.74	\$11.85
Energy (per kWh)		\$0.0274
	On Peak	\$0.1658
	Off Peak	\$0.0473
ATCO Electric (note 4)	Price Schedule D32	Price Schedule D31
Customer (per day)	\$1.35	\$1.35
Demand up to 500kW (per kW)	\$7.56	\$7.56
Demand over 500kW (per kW)	\$5.98	\$5.98
Energy (per kWh)	\$0.0048	\$0.0048
ENMAX Power (note 5)		
Residential (<5kV.A)	Rate D100	Rate D100
Total Customer Charge (per month)	\$7.96	\$7.96
Total Energy Charge (per kWh)	\$0.083691	\$0.083691
Medium Commercial (<25 kV.A)	Rate D300	Rate D300
Total Customer Charge (per month)	\$16.54	\$16.54
Total Demand Charge (per kW)	\$3.14	\$3.14
Total Energy Charge (per kWh)	\$0.009312	\$0.009312
Secondary Large Commercial (>25KV.A)	Rate D310	Rate D310
Total Customer Charge (per month)	\$16.54	\$16.54
Total Demand Charge (per kW)	\$2.77	\$2.77
	On Peak	\$0.014464
	Off Peak	\$0.005415

Notes:

- 1) BC Hydro Electric Tariff, Terms and Conditions of Service, pp. B-20. Effective December 20, 2000
- 2) SaskPower, Electric Service Business Policy: Non-Utility Generation, Sections 6.2.4, 6.3.4, 6.4.4. Effective September 1, 2000
- 3) Hydro Quebec Distribution Tariff, Chapter 5, Section 3, pp.65. Effective April 1, 2006
- 4) ATCO Electric 2006 Interim Distribution Tariff, Price Schedule D32. Effective January 1, 2006
- 5) ENMAX Power Corporation Distribution Tariff, Distributed Generation, Rate Code D600. Effective April 1, 2006.

2 **BC Hydro**

3 The Terms and Conditions of the BC Hydro Electric Tariff state that stand-by, emergency, or
 4 maintenance service is not available under any rate schedule, and will be supplied by BC
 5 Hydro only by special agreement specifying the rates, terms and conditions governing such
 6 service.

7

1 **SaskPower**

2 The Electric Service Business Policy for Non Utility Generation sets out the policy for three
3 classes of independent power producers: Small Power Producers, Non-Utility Generation of
4 100kW to 10MW, and Non Utility Generation Greater than 10MW. For each of these three
5 classes, stand-by service, if required, will be negotiated separately from Interconnection and
6 Operating Agreements.

7
8 **Hydro Quebec**

9 The Hydro Quebec Distribution Tariff, Chapter 5 General Rates for Large Power, sets out
10 Rate LD for delivery of emergency back-up electricity to large customers whose normal
11 independent source of energy has failed. The rate is available to customers whose normal
12 independent production plus minimum billing demand at applicable rate totals 5,000 kW or
13 more. Rate LD may be combined with the general rate for the part of the load supplied by
14 Hydro Quebec at all times.

15
16 The LD rate is designed with Time of Use considerations, for Winter Weekdays, defined as
17 between 6am and 10pm during all working days in the winter period. The available power for
18 a contract at Rate LD must be specified in a written agreement between the customer and
19 Hydro Quebec.

20
21 **ATCO Electric**

22 The 2006 Interim Distribution Tariff contains Price Schedule D32, for Generator
23 Interconnection and Stand-by Power. The rate is available for stand-by power to the on-site

1 load, in the event of a forced outage or derate of on-site generating equipment. Charges for
2 service in any one month shall be the sum of customer charges, demand charges²¹, energy
3 charges and other charges for deficient power and fixed charges. In the event that ATCO
4 Electric incurs an increase to the point of delivery billing demand with Alberta Electric
5 System Operator (AESO), as a result of a standby event (i.e. the new demand at the point of
6 delivery is coincident with and outage of the generator), then an additional charge equal to
7 the current AESO Demand Transmission Service rate times the incremental point of deliver
8 demand incurred. This charge will apply for the next twelve months inclusive of the current
9 billing period.

10

11 **ENMAX Power**

12 The Distribution Tariff for 2006 lists Rate Code D600 as the schedule for provision of
13 services with on-site generation less than 1,000 kV.A connected in parallel with the ENMAX
14 power distribution system. Stand-by rates for self generating customers are grouped into
15 four classes and are determined based on the capacity of the generator installed.

16

17 Self generating customers with a nominal output rating of 5 kV.A or less are subject to the
18 D100 Residential rate code. Customers with a nominal output rating of 25kV.A or less are
19 subject to the D300 Medium Commercial rate code. Customers with a nominal output rating
20 greater than 25kV.A, on the secondary side of the transformer, are subject to the D310
21 Secondary Large Commercial rate code. Rate code D410 applies to self generating

²¹ Demand Charges listed as cents/kW/day. Demand Charges converted to \$ per kW to facilitate comparison with other utilities.

1 customers with 25kV.A or more at primary voltage. Self generating customers with on-site
2 generation greater than 1,000 kV.A, will be reviewed on an individual basis.

3
4 Distribution connected generators are required to contract for demand capacity based on the
5 greater of peak demand and the generator nominal output rating. Any kV.A of demand that
6 occurs in excess of the contracted capacity will be charged at double the facilities charge in
7 the month of occurrence, and contract capacity will be increased by the amount of excess
8 demand for the following 12 months, inclusive of the current billing period. System usage
9 charges are determined using the sum of energy inflow and energy outflow at the point of
10 connection.

11

12 **Summary of Approaches**

13 Based on the review of stand-by rate offerings by other utilities in Canada, it appears that
14 there are three basic rate-making approaches to providing stand-by service:

15

- 16 • **Non-Interconnected Utilities do not offer Stand-by Services:** The two Canadian
17 electric utilities most similar to NTPC (Yukon Energy Corporation and Nunavut Power
18 Corporation) do not offer stand-by service on a published rate schedule.
19 Interconnected utilities may offer this service; however those utilities have the
20 opportunity, when the standby customer is using their own generation, of using
21 installed utility generation to make extraprovincial sales. In contrast, in NTPC's case it
22 must install sufficient generation to meet all firm loads and standby loads for peak

1 times (since it will have obligations to both sets of customers) but will have no ability
2 to make economic use of the capacity installed to service the stand-by customers
3 when they are using their own generation.

- 4
- 5 • **Limited or Case-by-Case Approach to Stand-by Service:** BC Hydro and
6 SaskPower do not have published rates intended to accommodate stand-by service.
7 The rate schedules for these utilities state that such service is only available under
8 special agreement with the utility, which specifies the rates, terms and conditions of
9 such service, and will be negotiated on a case by case basis.

- 10
- 11 • **Time Differentiated Stand-by Rates:** Hydro Quebec's stand-by rate has a time-of-
12 use component which heavily penalizes customers for stand-by service during peak
13 periods. The on-peak price is 3.5 times greater than the off peak price, and 6 times
14 greater than the standard L Rate. A time-differentiated stand-by rate recognizes that
15 any stand-by use during peak load periods imposes considerably greater capital
16 costs on the system than use during off-peak periods.

- 17
- 18 • **No Differentiation between Stand-by and Other Firm Rate Offerings:** ATCO
19 Electric and ENMAX Power both have rate schedules for stand-by service to self-
20 generating customers that mirror the cost of regular firm service, but with substantially
21 more stringent conditions with respect to contract demands, coincident peaks and
22 other demand-related factors. It should also be noted that unlike NTPC, these utilities
23 operate in wholesale markets with much greater generation diversity.

24

1 **Principles of Stand-by Rate Design**

2 Following the review of the stand-by rate designs used by other Canadian utilities, as well as
3 certain other publicly available information on the topic²² NTPC developed the following
4 principles related to the design of rates for Stand-by Service Customers:

5

6 **1. System load planning must account for the full potential load during unplanned**
7 **outages of self generating customers at the time of the system coincident peak.**

8 In order for the stand-by service to be useful to the customer, it must be considered
9 'firm' for capacity planning purposes. Compared to larger southern jurisdictions that
10 offer stand-by service at rates similar to the basic firm general service rate, the
11 Corporation has much more limited generation and load diversity in the communities
12 it serves. The Corporation also does not have the ability to import power to bridge any
13 short-term generation deficiencies. In order to protect existing customers and ensure
14 it can meet the obligations to stand-by customers, the Corporation must plan for the
15 ability to serve the full stand-by load at the time of the system peak.

16 **2. Stand-by rates must be designed to reflect the full cost of providing the service.**

17 This principle is required to ensure that the Corporation's other firm customers are not
18 subsidizing stand-by customers. This also allows potential self generating customers
19 to make economically efficient investment decisions based on undistorted prices.

20

²² See for example, Parmesano, H.S. 2003. Standby Service to Distributed Generation: The Wrong Tool for Subsidies. The Electricity Journal, October 2003.

1 **3. Stand-by Rate Design should recognize the Load Characteristics of Stand-by**
2 **Customers.** Although the Corporation has no load data for stand-by customers, it is
3 likely that stand-by customers would have a considerably lower load factor than other
4 firm general service customers (this is the basic premise for the service). While in the
5 2001/03 Phase II GRA the Corporation adjusted rates to capture more of its fixed
6 costs in the demand and customer charges, existing energy rates still capture a
7 substantial portion of the demand and customer costs. Under this rate structure, a
8 customer who uses very little energy compared to their peak demand will not cover
9 the costs they impose on the system. Therefore, it would be appropriate to have the
10 rates for stand-by customers reflect that different load profile with higher demand
11 charges than regular general service customers.

13 **Stand-by Rate Design Proposal**

14 The characteristics of the NTPC system and the need for prudence in planning for these
15 systems to protect existing ratepayers requires a cautious approach to rate design for
16 potential stand-by customers. NTPC would be prepared to serve firm stand-by customers
17 only under the types of rate structures and terms and conditions proposed in the 2001/03
18 Phase II rate application. NTPC's specific proposal is as follows:

19
20 1. Given the limited application of this rate offering, NTPC proposes to enter into
21 agreements with each customer setting out the terms for the supply of the stand-by
22 service and any specific limitations on the service that may be required. The
23 Corporation will file copies of any such agreements with the Board.

1 2. Stand-by service will only be available subject to the following conditions:

2 a. The customer must nominate a stand-by load to be served. NTPC will only
3 enter into a stand-by arrangement only where there it is technically feasible, in
4 NTPC's determination.

5 b. The customer must agree to terms that will include a minimum subscription
6 period, exit fees and re-subscription fees to be negotiated as part of the
7 service agreement.

8 c. The rates for the service will be adjusted from time to time with other public
9 rate offerings. The 2007/08 proposed stand-by charges are set out in Schedule
10 D. Energy consumed by the customer will be billed at the prevailing General
11 Service energy rate for that community.

12
13 The Corporation's proposed rate for this service is \$24/kW each month for all communities.

14 The stand-by load will not impact the calculation of a customer's winter demand ratchet for
15 the portion of their load taken on the standard General Service rate schedule. For example,
16 consider a case where a customer installs a 50kW genset and requests stand-by service for
17 that load but also regularly purchases an additional 25 kW at the prevailing General Service
18 rate, for a total load of 75kW. Normally, the customer will be billed \$24/kW for the 50kW
19 standby load plus \$8/kW for the 25 kW of General Service load each month. In the event the
20 50kW customer-owned genset is unavailable and the customer requires use of the stand-by
21 service, such that their total demand peak in that month is 75kW the Corporation will adjust
22 the customer's demand such that they continue to be billed 50 kW at the \$24/kW stand-by
23 rate and 25kW at the \$8/kW General Service demand rate. The differentiation in the demand

1 charge for stand-by service (\$24/kW) and general service (\$8/kW) is reasonable, because
2 most of the demand related costs for general service customers are recovered through the
3 energy charge. Since stand-by customers will purchase very little energy, their demand
4 charges must be higher to recover the costs to serve them.

5

6 The Corporation established this proposal based on the following rate design
7 considerations:

8

- 9 1. Schedule D shows the full-cost demand charge related to generation functions in
10 each community based on the cost of service method used in the 2001/03 Phase II
11 GRA updated for 2007/08 costs and sales information. For most of the thermal
12 communities the full cost generation demand component is approximately \$24 each
13 month.
- 14 2. For reasons of customer understandability and ease of administration, the
15 Corporation considered it appropriate to have the same demand charge in each
16 community for this service. This is consistent with the demand charges for general
17 service customers, which are levelized across communities.

18

19 **Interconnection Guidelines**

20 NTPC has reviewed the interconnection guidelines of other utilities. NTPC has prepared
21 interconnection guidelines proposed to be applicable to any customer who seeks to receive
22 standby service or otherwise self-generate all or a portion of their power while connected to

- 1 NTPC's distribution system. These proposed standards were approved on an interim basis
- 2 in Decision 13-2007 and the Corporation is now seeking final approval of the guidelines.

Friday, August 15, 2008

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application

Schedule D: Stand-by Rates for General Service Customers

Plant Number	Community	Full Cost Customer Charge	Full Cost Demand Charge	Generation Related Demand Charge	Proposed Stand-by Demand Charge
		(\$/customer/month)	(\$/kW)	(\$/kW)	(\$/kW)
		A	B	C	D
101	Yellowknife				
108	Behchoko	170.03	23.87	4.88	24.00
109	Dettah	167.37	17.81	6.26	24.00
104	Wha Ti	164.40	40.63	25.60	24.00
105	Gameti	302.70	77.17	42.21	24.00
110	Lutsel K'e	164.40	40.63	23.72	24.00
201	Fort Smith	55.15	15.65	5.82	24.00
203	Fort Resolution	160.26	31.66	14.76	24.00
205	Fort Simpson	225.38	41.56	23.56	24.00
206	Fort Liard	215.99	23.45	13.96	24.00
207	Wrigley	262.88	64.90	36.24	24.00
208	Nahanni Butte	251.15	95.52	49.51	24.00
209	Jean Marie River	244.99	83.22	45.45	24.00
301	Inuvik	201.24	42.52	24.23	24.00
304	Norman Wells	27.59	8.80	4.96	24.00
305	Tuktoyaktuk	120.59	31.97	25.12	24.00
306	Fort McPherson	108.16	52.24	43.24	24.00
307	Aklavik	102.79	33.78	24.80	24.00
308	Deline	131.78	34.41	23.13	24.00
309	Fort Good Hope	158.45	40.61	29.57	24.00
310	Tulita	116.46	53.16	42.91	24.00
311	Paulatuk	141.19	78.98	61.40	24.00
312	Sachs Harbour	216.12	94.39	59.29	24.00
313	Tsiigehtchic	166.76	56.28	36.34	24.00
314	Colville Lake	276.63	186.06	110.20	24.00
315	Ulukhaktok	132.76	34.82	21.12	24.00

**Distributed Resource
Technical Interconnection Guideline**

DRAFT

Prepared by the Northwest Territories Power Corporation

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1.0 INTRODUCTION

This guideline sets out the criteria and technical requirements for interconnection of a Distributed Resource (“DR”) operating at a voltage of 25,000 volts or lower (that is not exclusively owned by the Wires Owner) to a Wires Owner’s facilities. DR includes both generation and energy storage technology. This guideline provides the requirements across a broad spectrum of matters relevant to performance, operation, testing, safety and maintenance of a DR interconnection. This guideline has been developed with reference to international standards, including the Institute of Electrical and Electronic Engineers (“IEEE”), as well as utility practices in other jurisdictions.

The addition of a DR to a Distribution System may result in a change to the Distribution System configuration and hence system reliability. Achieving and maintaining a technically sound and robust interconnection between a DR and the Distribution System requires diligence on the part of everyone involved in the interconnection, including designers, manufacturers, users, owners and operators of both the DR and the Distribution System. Consequently, the requirements in this guideline need to be understood and cooperatively complied with by all of those parties.

This guideline does not constitute and is not intended to be a comprehensive guide or handbook for designing, constructing or operating a DR. Persons considering the development of a DR should engage the services of qualified individuals to provide electrical design and consulting services. Further, this guideline does not constitute an offer to, or express an interest in, purchasing capacity and energy from DR projects. Commercial arrangements related to the delivery of electrical energy and capacity from DR projects must be discussed and agreed upon with the relevant Wires Owner.

Section 2 of this guideline sets out further cautions respecting the limitation of use of this guideline. Section 3 provides definitions for the terms and references used in this guideline. Section 4 sets out general interconnection and protections requirements. Section 5 addresses construction requirements. Section 6 provides metering requirements. Section 7 addresses inspection and equipment testing matters. Section 8 provides the data requirements for approval of DR projects. Section 9 addresses equipment marking and tagging. Section 10 specifies the maintenance requirements. Section 11 contains various tables which list interconnection protection requirements. Lastly, the Appendices set out (1) the applicable codes and standards, (2) single line drawings illustrating typical interconnection arrangements, (3) metering accuracy tables and (4) reference notes.

2.0 LIMITATIONS

The criteria and requirements in this guideline are applicable to all DR technologies and the primary and secondary voltages of a Distribution System. Installation of a DR on radial primary and secondary Distribution Systems is the main emphasis of this version. In addition, the requirements shall be met at the Point of Common Coupling (“PCC”), although the location of the protective devices may not necessarily be at that point.

This guideline is a minimum requirement for the interconnection of a DR. Additional requirements may have to be met by both the DR Owner and the Wires Owner to ensure that the final interconnection design meets all local and national standards and codes, and that the design is safe for the intended application.

The Wires Owner shall not be liable for any damage, injury, loss, costs or claims suffered or incurred by the DR Owner, its agents or employees as a result of this standard. The DR Owner shall not be liable for any damage, injury, loss, costs or claims suffered or incurred by the Wires Owner, its agents or employees as a result of this standard. This guideline does not address any liability provisions provided for elsewhere, such as in interconnection and operating agreements between the DR Owner and the Wires Owner, or the Wires Owner’s tariff.

The DR Owner is also responsible for making required changes to the DR Owner’s facilities as required to meet new or revised standards or due to system changes. In addition, when advised by the Wires Owner, the DR Owner will make changes requested by the Wires Owner to the DR Owner’s facilities. Therefore the DR Owner must make provision to accommodate such changes efficiently. The DR Owner shall be responsible for the cost of any required changes, including those changes requested to be made by the Wires Owner.

This guideline does not absolve the DR Owner of responsibility to protect their equipment, the Wires Owner’s equipment, and personal and public safety.

3.0 DEFINITIONS

“Alternating Current” or **“AC”** means an electric current that reverses direction at regularly recurring intervals of time and has alternating positive and negative values.

“Anti-Islanding” means system design to detect and disconnect from a stable unintended Island with matched load and generation. Reliance solely on under/over voltage and frequency trip is not considered sufficient to qualify as Anti-Islanding.

“ANSI” means American National Standards Institute.

“**CSA**” means the Canadian Standards Association.

“**Direct Current**” or “**DC**” means a unidirectional electric current in which the changes in value are either zero or so small that they may be neglected.

“**Distributed Generation**” or “**DG**” means electric generation facilities connected to a Distribution System through the PCC. DG is a subset of DR.

“**Distributed Resource**” or “**DR**” means sources of real electric power that are not directly connected to the bulk power transmission system, including both generation and energy storage technology.

“**Distribution System**” means any facilities that operates at a nominal voltage of 25,000 volts or lower and that allow electric power to be delivered to a load, regardless of ownership.

“**DR Owner**” means anyone interconnected to the Wires Owner’s system for the purpose of generating electric power.

“**Hertz**” or “**Hz**” means the unit of frequency for alternating current.

“**IEEE**” means the Institute of Electrical and Electronic Engineers.

“**Island(ing)**” means a condition in which a portion of the Wires Owner’s system is energized by one or more DR Owner generators through their PCC(s) while electrically separated from the rest of the Wires Owner’s system.

“**Parallel Operation**” means, with reference to the Wires Owner, any electrical connection between the Wires Owner and the DR Owner’s generation equipment.

“**Point of Common Coupling**” or “**PCC**” means the point where the electrical facilities or conductors of the Wires Owner are connected to the DR Owner’s facilities or conductors, and where any transfer of electric power between the DR Owner and the Wires Owner takes place.

“**OCR**” means oil circuit re-closure.

“**Operation Indicator (Target)**” means a supplementary device operated either mechanically or electrically, to indicate visibly that the relay or device has operated or completed its function.

“**Stabilized**” means the state of the Distribution System after voltage and frequency have returned to normal range for a period of at least five minutes (or another period of time as coordinated with the Wires Owner) following a disturbance.

“Telemetry” means the transmission of measurable quantities using telecommunications techniques.

“Trip Time” means the time between the start of the abnormal condition and the interconnection device ceasing to energize the Wires Owner’s Distribution System.

“Visible-break Disconnect” means a disconnect switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. The switch or breaker shall be provided with the means for adequate visible inspection of all contacts in the open position, and the blades or moving contacts shall be connected to the generator side.

“voltage” means the electrical force or potential that causes a current to flow in a circuit measured in Volts (“V”) or kiloVolts (kV). 1 kV = 1000 V.

“Wires” means the electric utility distribution system below 25 kiloVolts to which the generation equipment is interconnected.

“Wires Owner” means the electric utility which owns the Distribution System.

4.0 GENERAL INTERCONNECTION AND PROTECTION REQUIREMENTS

The DR Owner’s generation and interconnection installation must meet all applicable national, provincial and local construction and safety codes.

Any DR Owner may operate 60 Hertz, three phase or single phase generating equipment, in parallel with the Wires Owner’s System and in accordance with interconnection and operating agreements with the Wires Owner, subject to the equipment and DR Owner meeting or exceeding the requirements of this guideline and the Wires Owner’s approval.

The following three sections, 4.1, 4.2, and 4.3, define the system technical requirements. The DR Owner’s equipment must be able to operate within the ranges specified in section 4.1. The technical requirements to be met by the DR Owner are described in section 5.2. Section 5.3 provides the technical requirements to be met by the facilities interconnecting the producing facility and the distribution system.

These requirements promote safe operation and minimize the impact on the electrical equipment in the Wires Owner’s system and its other customers. These guidelines are not intended to provide protection for the DR Owner’s generation equipment. It is the responsibility of the DR Owner to provide such protection. The DR Owner is responsible for protecting the DR Owner’s generating equipment in such a manner that Distribution System outages, short circuits or other disturbances, including excessive zero sequence currents and

ferro-resonant over-voltages, do not damage the DR Owner's generating equipment. The DR Owner's protective equipment shall also prevent excessive or unnecessary tripping that would affect the Wires Owner's system reliability and power quality to other customers as required in this guideline.

The DR Owner is required to install, operate and maintain in good order and repair at all times in conformity with good electrical practice the facilities required by this guideline for the safe parallel operation with the Wires Owner's system. Refer to Tables 1, 2 and 3 and Appendix 2 for summary tables & single line diagrams showing typical interconnection protection requirements.

4.1 Distribution System

4.1.1 System Frequency

The Northwest Territories interconnected system operates at 60 Hertz ("Hz") Alternating Current ("AC"). Frequency deviations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, but where the Northwest Territories interconnected system remains intact.

4.1.2 Voltage Regulation

CSA Standard CAN3 C235 83 - Preferred Voltage Levels for AC Systems 0 to 50,000 V provides general guidance as to appropriate performance.

4.1.3 Power Quality

All interconnected equipment must comply with the Wires Owner's standards for power quality. The following industry standards may provide guidance as to appropriate performance:

- Voltage Flicker - IEEE Std. 519-1992 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems; and
- Harmonics - IEEE Std. 519-1992 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

4.1.4 Voltage Unbalance

Phase to phase voltage unbalance can be expected on the primary distribution system. During normal steady state operation, phase to phase voltage unbalance is normally less than 3%. In some remote locations, unbalances may be higher. The DR Owner should consult with the Wires Owner to obtain site specific details.

Voltage unbalance is defined as follows:

$$\text{Unbalance (\%)} = \frac{100 \times (\text{maximum deviation from average phase voltage})}{\text{Average phase to phase voltage}}$$

4.1.5 Fault Levels

Fault levels and maximum allowable fault levels, vary significantly through a Distribution System and must be considered in the design of the interconnection. Fault levels and X/R ratios must be evaluated for the equipment selected.

4.1.6 System Grounding

Distribution facilities are typically operated as effectively (solidly) grounded and Wye-connected at the source substation bus. Other configurations are occasionally found. Distribution System grounding must conform to the *Alberta Electrical and Communication Utility Code*, 2nd Edition, 2002, declared in force pursuant to the *Electrical Code Regulation*, Alta. Reg. 145/2002, as amended or replaced.

4.1.7 Fault and Line Clearing

To maintain the reliability of the Distribution System, the Wires Owner may use automatic re-closing. The DR Owner needs to take into consideration line re-closing when designing generator protection schemes. This is to ensure that the generator is disconnected from the Distribution System prior to automatic re-close of breakers. The DR Owner may reconnect when the Distribution System voltage and frequency return to normal range and is stabilized. To enhance reliability and safety and with the Wires Owner's approval, the DR Owner may employ a modified relay scheme with tripping or blocking using communications equipment between the DR Owner's and the Wires Owner's facilities.

4.2 Generating Facility

4.2.1 Mitigation of Adverse Effects

Adding a generating facility can adversely affect the electric service to existing or future electric customers. The DR Owner shall work with the Wires Owner to mitigate any adverse affects.

If the generating facility is affecting customers adversely, the Wires Owner may disconnect it until such time as the concern has been mitigated. The DR Owner will be responsible for any costs incurred as a result of these actions.

4.2.2 Synchronism

Any generating facility that can create a voltage while separate from the electric system must have synchronization facilities to allow its connection to the electric system.

Inverter-type, voltage-following equipment that cannot generate a voltage while separate from the electric system does not require synchronization facilities. Nor do induction generators that act as motors during start-up, drawing power from the electric system before they themselves generate power.

The DR Owner has the responsibility to synchronize and maintain synchronization to the Wires Owner's system. The Wires Owner cannot synchronize to the generating facility. A proposed synchronizing scheme must be submitted by the DR Owner and outlined in interconnection and operating agreements with the Wires Owner.

Distribution and transmission facilities typically allow for automatic re-closing of electrical circuits after a variable time delay. The DR Owner is responsible for protecting their own facility from the impacts of such re-closing.

Generators can automatically restart following automatic re-closing of distribution facility electrical equipment if agreed to by the Wires Owner. Generators that automatically restart must have time delay on restart adjustable as agreed to by the Wires Owner. The Wires Owner will coordinate the settings of generator restart time-delays so that generators on any individual feeders restart in staggered order.

4.2.3 Voltage Regulation and Power Factor

The DR Owner shall be responsible for ensuring that the voltage levels at the PCC are maintained within the guidelines prescribed by the Wires Owner and/or at least equal to the voltage levels, during feeder peak load conditions, prior to the interconnection.

Synchronous generators connected to the Distribution System must be equipped with excitation controllers capable of controlling voltage. The generator-bus voltage set-point shall be stable at and adjustable to any value between 95% and 105% so that the Wires Owner can maintain CSA standard voltage limits on its system.

Induction generators do not have voltage or reactive power control and consume reactive power. In this case, the generator must provide reactive compensation to correct the power factor to ± 0.90 at the PCC, unless other terms are negotiated with the Wires Owner.

Inverter-type generating equipment can control the power factor over a wide range, typically ± 0.75 . An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9 . The DR Owner may operate outside that range by agreement with the Wires Owner.

The Wires Owner will define voltage and reactive power control requirements on a project-by-project basis. Together, the DR Owner and the Wires Owner will

identify the exact transformer ratio to allow best voltage regulation on the system, and whether an on-load tap-changer is needed.

In order to coordinate with its existing voltage control devices, the Wires Owner may require that the generator operate in a power factor control mode (i.e. within a constant power factor set-point range). The voltage/power factor regulator shall be capable of controlling the power factor of the generator between +0.90 and -0.90. The Wires Owner shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator shall have a voltage override that causes it to reduce excitation if the voltage at the PCC exceeds an upper limit to be specified by the Wires Owner. The normal upper limit is 105% of nominal, however, the voltage regulator shall have provision to adjust this upper limit between 100 and 110% of nominal. The voltage regulator shall also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment shall have provision to allow for the adjustment of this time delay between 0 and 180 seconds. The Wires Owner will specify the required time delay.

4.2.4 Frequency Control

A DG must remain synchronously connected for frequency excursions as identified in this guideline and the table below.

For generators connected to the Wires Owner, Islanded operations are not allowed (see section 4.3.10). Generators that serve remote isolated systems must be capable of controlling the frequency of the system to between 59.0 Hz to 61.0 Hz for normal operation. Under certain operating conditions, frequency tolerances may need to be operated within a smaller bandwidth.

The frequency of the electric system is controlled by all synchronous generator governor systems that connect to the electric system. Such governor systems respond automatically to changes in system frequency to prevent further deviation. Synchronous generators and other generators with stand-alone capability and significant capacity in relation to the current system's installed capacity must have a speed droop governor. The droop setting of the governor shall be 5% and the governor system must be operated at all times so that it is free to respond to system frequency changes. If a 5% setting is not possible, the DR Owner must obtain approval from the Wires Owner for an alternate droop setting.

4.2.5 Voltage Unbalance

Any three-phase generating facility must have a phase-to-phase voltage unbalance not exceeding 1%, as measured both with no load and with balanced three-phase loading. Voltage unbalance will be calculated using:

$$\text{Unbalance (\%)} = \frac{100 \times (\text{maximum deviation from average phase voltage})}{\text{Average phase to phase voltage}}$$

Single-phase generators must not adversely unbalance the three-phase system. When they are connected in multiple units, an equal amount of generation capacity must be applied to each phase of a three-phase circuit, and the group of generators must maintain balance when one unit trips or begins generating before or after the others. A single one-phase generator may be connected alone only if it does not cause voltage unbalance on the distribution system in excess of 2%.

4.2.6 Resonance and Self Excitation of Induction Generators

Resonance should be considered in the design of the DR Owner's facility, as certain resonance can cause damage to existing electrical equipment, including the electrical equipment of the DR Owner. Engineering analysis by the DR Owner should be a part of the design process to evaluate and eliminate the harmful effects of:

- ferro-resonance in the transformer (see Appendix 4, Note 1);
- sub-synchronous resonance due to the presence of series capacitor banks (see Appendix 4, Note 2); and
- resonance with other customers' equipment due to the addition of capacitor banks to the distribution system (see Appendix 4, Note 3).

In the event that an induction generator is used by the DR Owner, the adverse effects of self-excitation of the induction generator during Island conditions should be assessed and mitigated. The intent is to detect and eliminate any self-excited condition (see Appendix 4, Note 4).

The engineering analysis of resonance and the assessment of the effect of self-excitation of induction generators should be submitted to the Wires Owner for their approval or further evaluation.

4.3 Interconnection

4.3.1 Safety

Safety of personnel, the public and of equipment is of primary concern in the design of the interconnection.

4.3.2 Point of Common Coupling

The Point of Common Coupling or PCC is the point where the Wires Owner's electrical facilities or conductors are connected to the DR Owner's facilities or conductors, and where any transfer of electric power between the DR Owner and

the Wires Owner takes place. The PCC will be identified in the design and on the single line diagram. The Wires Owner will coordinate design, construction, maintenance and operation of the facilities on the distribution side of the PCC. The DR Owner is responsible for the design, construction, maintenance and operation of the facilities on the generation side of the PCC.

In specific cases, either the Wires Owner or the DR Owner may own equipment located on the other party's side of the PCC. For example, the Wires Owner may own and operate communications, supervisory, or metering equipment, which is located on the DR Owner's side of the PCC.

The DR Owner must provide a site with the necessary space for the Wires Owner to install current transformers, potential transformers, switching equipment, meters and any other controls or communications equipment required to interconnect with the generating facility. The site is to be approved by the Wires Owner and a 120-volt AC power service is to be available at no cost for the use of portable tools.

The DR Owner is responsible for paying any incremental costs to the transmission/distribution systems caused by the generator. The Wires Owner will carry out the engineering, design and construction required for its system; and charges these costs back to the DR Owner. The Wires Owner will recover ongoing O&M costs required on the distribution feeder side.

4.3.3 Point of Disconnection

The disconnect switch can be on the high or low voltage side of the interconnection transformer if required. When the interconnection involves three phase generators the disconnect switch must be gang operated to simultaneously isolate all three phases.

High Voltage - Disconnect Switch

The disconnect switch on the Wires Owner's side of the interconnection transformer (e.g. 25 kV airbreak) will be installed, owned and maintained by the Wires Owner.

Low Voltage - Disconnect Switch

A manual visible disconnect switch is required so that the power system can be isolated in order to work on the facilities. Appendix 2 illustrates sample configurations. The DR Owner is responsible for the disconnect switch installation. All low voltage disconnect switches shall:

- be adequately rated to break the connected generation load;
- be within 5 meters (horizontal) of the interconnection point, or wire owner approved location;

- have contact operation verifiable by direct visible means;
- be readily accessible to the Wires Owner operating personnel;
- have provision for being locked in the “open” position;
- disconnect all ungrounded conductors of the circuit simultaneously;
- be externally operable without exposing the operator to contact with live parts;
- be capable of being closed with safety to the operator with a fault on the system;
- be capable of being energized from both sides;
- plainly indicate whether in the “open” or “closed” position;
- be labeled with a Wires Owner switch number;
- meet applicable CSA Part II standards;
- be installed to meet all applicable codes;
- provide safe isolation for the Wires Owner’s personnel from the generators and all other possible customer sources of power; and
- be annually inspected and maintained.

The disconnect switch on the generation side of the interconnection transformer will be owned and maintained by the DR Owner.

For a site that interconnects multiple generators, one disconnect switch must be capable of isolating all the generators simultaneously.

There may be other means of meeting this requirement. The Wires Owner must approve any other means.

The DR Owner shall follow the Wires Owner’s switching, work protection procedures in which the Wires Owner shall instruct the DR Owner.

4.3.4 Phasing

Phasing is not standardized across Distribution Systems. Therefore, the phase sequence and the direction of rotation must be coordinated between the Wires Owner and the DR Owner.

4.3.5 Interconnection Grounding

Grounding configurations shall be designed to provide:

- solidly grounded distribution facilities;
- suitable fault detection to isolate all sources of fault contribution, including the generator, from a faulted line or distribution element;
- a circuit to block the transmission of harmonic currents and voltages; and
- protection of the low voltage side from high fault current damage.

The preferred configuration is delta connection on the generator side of the transformer and a grounded Wye configuration on the Wires Owner's side of the transformer. If this configuration is not possible, the configuration chosen must still address the above concerns. The winding configuration for DR Owner interconnection transformers should be reviewed and approved by the Wires Owner.

4.3.6 Interrupting Device Ratings

The design of DR must consider the fault contributions from both the Distribution System and the generating facility itself, to ensure that all circuit fault interrupters are adequately sized. The Wires Owner will inform the DR Owner of the present and anticipated future fault contribution from the interconnected electric system.

4.3.7 Phase and Ground Fault Protection

The DR Owner must install protective devices to detect and promptly isolate the generating facility for faults occurring either in the generating facility itself or on the distribution system. "Virtual devices" (i.e. computer or programmable-logic-controller systems) are acceptable provided that they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The DR's protective devices must fully coordinate with protective relays on the electric system unless otherwise agreed by the Wires Owner. The DR Owner must calculate the protective device settings and submit the relay characteristics and settings to the Wires Owner for review and approval.

The DR must be able to detect the following situations and isolate itself from the distribution system for:

- loss of any phase(s);
- a short circuit between any phase(s) and ground; and

- a short circuit between phase(s).

4.3.8 Over-voltage and Under-voltage Protection

The DR Owner will operate its generating equipment in such manner that the voltage levels on the Wires Owner's system are in the same range as if the generating equipment were not connected to the Wires Owner's system.

The DR Owner must install necessary relays to trip the circuit breaker when the voltage, measured phase to ground, is outside predetermined limits. Under voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over voltage relays should be adjustable and may be instantaneous.

The DR Owner's interconnection device shall cause the generator to cease to energize the Wires Owner's distribution system within the Trip Time specified in the table below.

Response to Abnormal Voltages

RMS Voltage	Trip Time
$V \leq 60$ ($V \leq 50\%$)	Instantaneous
$60 < V < 108$ ($50\% < V < 90\%$)	120 cycles
$108 \leq V \leq 127$ ($90\% < V < 106\%$)	Normal Operation
$127 < V < 144$ ($106\% < V < 120\%$)	30 Cycles
$V \geq 144$ ($V \geq 120\%$)	Instantaneous

The DR Owner may reconnect when the Wires Owner's system voltage and frequency return to normal range and is stabilized as permitted in interconnection and operating agreements.

4.3.9 Over Frequency and Under Frequency Protection

The DR Owner must install frequency selective relays to separate the DR from the Distribution System in cases of extreme variations in frequency.

Under frequency and over frequency relaying that automatically disconnects generators from the distribution system shall be time delayed in accordance with the Wires Owner requirements specified in section 4.2.4. The DR Owner may reconnect when the Distribution System voltage and frequency return to normal range and is stabilized as permitted in interconnection and operating agreements.

4.3.10 Anti-Islanding

The DR Owner's generator shall be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the Wires Owner.

At the discretion of the Wires Owner, the DR Owner will install under-frequency tripping at 59.0 Hz and over frequency tripping at 61.0 Hz at a time delay as permitted in interconnection and operating agreements.

In most cases, the DR will routinely operate as a part of the interconnected system. A problem on the system could lead to the generator becoming Islanded (i.e., the sole producer of power to one or more of the Wires Owner's customers). In turn, this could lead to damages to those customers caused by irregularities in power quality. To prevent this, the DR Owner must use tele-protection signals from the Distribution System or other reliable means to separate the DG from the Distribution System upon Islanding. The DR Owner is responsible for damages caused as a result of failure to safely separate during an Islanding event.

For situations where there could be a reasonable match between the DR Owner generation and Islanded load, conventional methods may not be effective in detecting Islanded operation. In this event the Wires Owner will require the addition of transfer trip communication facilities to remotely trip off the DR Owner generation upon opening of the distribution feeder main circuit breaker or circuit re-closer.

4.3.11 Telemetry and Targeting

Where a DG could adversely affect the power system, the DR Owner must have systems in place to inform the Wires Owner of what protective operations occurred and failed to occur. An example of an adverse effect would be the DR Owner's generator providing inflow into a fault.

4.3.12 Requirements for Transfer Trip

All synchronous generators connected to the Distribution System shall be equipped with transfer trip protection to ensure that these machines do not Island in the event of substation breaker or intermediate oil circuit re-closure ("OCR") operation. General requirements are:

- generator separation within 0.6 seconds of breaker or OCR operation;
- fail safe lock out within 6 seconds of communication loss; and
- the DR Owner has responsibility for detecting and tripping in the event of communication loss.

Transfer tripping requirements are also applicable to induction generators, unless the DR Owner can demonstrate to the satisfaction of the Wires Owner that there is no potential for self- excitation.

4.3.13 Special Interconnection Protection

In some cases it will be necessary to provide for special generator-specific protection and controls, such as out-of-step or loss of synchronism.

The DR Owner needs to be aware that unbalance conditions can occur in the Distribution System, especially under system fault conditions, and the design of the interconnection facilities should take this into account.

For star-delta interconnection transformers, the unbalance fault current could damage the generator interconnection transformer under certain fault conditions, as a result of the circulating current, which occurs in the delta winding of the interconnection transformer in an attempt to balance the fault current. The design may therefore require protection for the transformer to address this potential issue.

4.3.14 Flicker

The DR Owner is required to ensure that the operation of the DR Owner's facility will not cause voltage variations on the Wires Owner's system that could result in excessive lamp flicker for the Wires Owner's customers. If the DR Owner's facility utilizes a prime mover that has a fluctuating power output (eg. wind power, slow speed reciprocating engine, etc), the DR Owner must ensure that the fluctuations in power output do not cause voltage variations, which exceed the Wires Owner's acceptable limits. Please refer to IEEE Std. 519-1992 IEEE Recommend Practice and Requirement for Harmonic Control in Electric Power Systems.

4.3.15 Harmonics

Operation of DG must not cause an unacceptable level of harmonics. Maximum harmonic current distortion limits for power generation equipment, measured at the PCC, are as specified in Table 10.3 of IEEE Std. 519-1992 IEEE Recommend Practice and Requirement for Harmonic Control in Electric Power Systems.

The objective of the current distortion limits in IEEE Std. 519 is to limit the harmonic injection from individual customers. This is to ensure that they do not cause unacceptable voltage distortion levels to normal system characteristics. The voltage distortion shall then be limited to 3% of the fundamental frequency for individual harmonic frequencies and 5% voltage total harmonic distortion on the Wires Owner's side of the PCC.

DR Owner's facilities must not inject Direct Current greater than 0.5% of the full rated output current into the Wires Owner's distribution system under normal or abnormal operation conditions.

4.3.16 Protection from Abnormal Conditions

The DR Owner's interconnection facilities shall be adequately protected from or able to withstand abnormal conditions on the Wires Owner's distribution system. This may include, but is not limited to:

- frequency excursions due to disturbances on the Wires Owner's Distribution System;
- partial or complete loss of load as a result of disturbances on the Wires Owner's Distribution System;
- transient over-voltage as a result of lightning or switching events; and
- over-voltage due to resonance conditions, healthy phase voltage rise during faults, self excitation and loss of load.

The DR Owner's facility must be self-protecting to prevent damage as a result of the normal or abnormal operation of the Wires Owner's Distribution System. The DR Owner is accountable for the execution of studies to identify potential abnormal conditions and the cost of mitigating the effects of abnormal conditions.

4.3.17 Self Excitation

Self-excitation of a synchronous generator can occur if the generator plus a portion of the Wires Owner's system become isolated from the rest of the Wires Owner's system, resulting in an Island. In an Island condition, self-excitation of the generator resulting from line capacitance or capacitors on the Wires Owner's system exceeds the capability of the generator and its excitation/voltage regulator system to control the voltage.

Unless the DR Owner can demonstrate through the execution of analytical studies, that there is no risk of self-excitation of the generator, the DR Owner must ensure, to the Wires Owner's satisfaction that:

- the DR Owner's facility has protection systems to detect a self-excitation condition;
- the interrupting device provided by the DR Owner is capable of switching the anticipated leading power factor current at the anticipated elevated voltages; and
- isolation of the DR Owner will occur quickly enough to preclude damage to other customers or the Wires Owner's system from the abnormal voltages that may occur.

4.3.18 Inadvertent Energization of the Wires Owner's Facilities

The DR's generator shall not energize the Wires Owner facilities when the Wires Owner's facilities are de-energized.

4.3.19 Protection from Electromagnetic Interference

The influence of electromagnetic interference shall not result in the change in state or mis-operation of the interconnection system.

4.3.20 Surge Withstand Performance

The interconnection system shall have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1.

4.3.21 Synchronization

Interconnection shall be prevented when the DR's synchronous generator and/or powers system is operating outside of the following limits.

Aggregate Rates of Generation (kVA)	Frequency difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500-1500	0.2	5	15
>1500	0.1	3	10

4.4 Typical Interconnection Requirements

While the typical interconnection requirements for safely operating the DR Owner's equipment in parallel with the Wires Owner's System are specified below, specific interconnection locations and conditions may require more restrictive protective settings or hardware especially when exporting power to the Wires Owner's Distribution System. The Wires Owner shall make these deviations known to the DR Owner as soon as possible, subject to review on an individual basis.

Protective relays, electric conversion devices, or other devices may comply with this guideline by the DR Owner demonstrating that such devices can accomplish the required protective function specified as applicable in section 12, Tables 1, 2 or 3.

4.4.1 Single-Phase Generators

Section 12, Table 1 shows the protective functions required to meet this guideline. Inverter type generators must meet the criteria in IEEE 929 -

Recommended Practice for Utility Interface of Photovoltaic (PV) Systems and be certified to UL 1741 and CSA 22.2 #107.1.

4.4.2 Three-Phase Synchronous Generators

Section 12, Table 2 shows the protective functions required to meet this guideline.

The DR Owner's generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The DR Owner is solely responsible for properly synchronizing its generator with the Wires Owner's system. The DR Owner is also responsible for ensuring that the interconnection protection device settings coordinate with the Wires Owner's protective device settings.

4.4.3 Three-Phase Induction Generators and Inverter Systems

Section 12, Table 2 shows the protective functions versus generator size required to meet this guideline.

Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured on the Wires Owner's side at the PCC is within the flicker limits. Otherwise, the DR Owner may be required to install hardware or other techniques to bring voltage fluctuations to acceptable levels.

Inverter type generators must meet the applicable criteria in IEEE 929 and be certified to UL 1741 and CSA 22.2 #107.1. This also applies to induction generators and self-commutation inverters.

Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters (whether of the utility-interactive type or stand-alone type) shall be used in parallel with the Wires Owner's system only with synchronizing equipment. Direct current generation shall not be directly paralleled with the Wires Owner's system.

4.4.4 Generators Paralleling for 6 cycles or less (Closed Transition Switching)

Section 12, Table 3 shows the protective functions required by this guideline for generators, which parallel with the Wires Owner for 6 cycles or less.

Generators meeting this requirement shall apply for Parallel Operation, shall enter into interconnection and operating agreements with the Wires Owner and shall otherwise meet the requirements of this guideline.

4.4.5 Mitigation of Protection System Failure

Relays with self-diagnostic check features provide information on the integrity of the protection system and should be used whenever possible. The design of protection should be done by a qualified engineer, or a competent technical person, working with the Wires Owner's engineers to ensure that the self-diagnostic check feature be integrated into the overall protection system for the safe and reliable operation of the power system.

Dependent on the system and its design, where relays with the self-diagnostic check feature do not trip the appropriate breaker(s), sufficient redundant or backup protection should be provided for the power system. The malfunctioning relay should also send a signal to notify operating personnel to initiate investigation of the malfunction.

Older electro-mechanical relays do not generally come with such self-diagnostic features. Design of protection and control systems in this case should generally be of a fail-safe nature to maintain the integrity of the protection system under protection system malfunction conditions.

4.4.6 Maximum Generator Power to be Exported

Where the DG capacity exceeds the load carrying capacity of the generator interconnection at the PCC or exceeds the capacity of the Wire Owner's Distribution System connected to the generator, the DR shall install protection to limit the amount of export power to the rated capacity of the Distribution System or the contracted export amount, whichever is less. The maximum limit on the amount of power to be exported shall be set out in an interconnection and operating agreement.

4.5 Interconnection Protection Approval

The DR Owner shall provide to the Wires Owner complete documentation on the proposed interconnection protection for review against the requirements of this guideline and potential impacts on the Wires Owner's system.

The documentation should include:

- a completed application form;
- an overall description on how the protection will function;
- a detailed single line diagram;
- the protection components details (manufacturer, model);
- the protection component settings (trigger levels and time values);
and

- the disconnect switch details (i.e. manufacturer, model and associated certification).

The DR Owner shall revise and re-submit the protection information for any proposed modification.

5.0 CONSTRUCTION

5.1 General

The DR Owner's facility shall be constructed and installed to meet all applicable regulations. All permitting and safety codes compliance must be completed and copies of inspection reports provided to the Wires Owner prior to energizing the PCC.

All single line diagrams (original or electronic versions) provided to the Wires Owner shall be drawn in accordance with IEEE standards and conventions, and shall be stamped by a professional engineer assuming responsibility for the design.

6.0 METERING

6.1 General

Metering shall comply with Measurement Canada requirements and shall:

- be suitable for use in the environmental conditions reasonably expected to occur at the installation site over the course of a typical year;
- be appropriate for the power system characteristics reasonably expected to exist at the installation site under all power system conditions and events; and
- be approved by the Wires Owner.

The primary side of the interconnection transformer, which is the side connected to the Distribution System, is the metering billing point for the DR Owner's generation export conditions. The low side of the interconnection transformer, which is the side connected to the DR Owner's facilities, is the metering billing point for the DR Owner's import conditions. On all installations where the metering equipment is installed on the low side of the interconnecting transformer, transformer loss compensation shall be installed in the meter for generation export conditions.

6.2 Meter Requirements

The meter must:

- be Measurement Canada approved under subsections 9(1), 9(2) 9(3) of the *Electricity and Gas Inspection Act*, as amended or replaced;
- be verified and sealed in accordance with the *Electricity and Gas Inspections Act*, as amended or replaced, subject to the terms and conditions of any applicable dispensation(s);
- be a bi-directional four quadrant meter;
- include an interval time-stamping clock, if the meter provides the interval data time-stamping function, capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter according to Mountain Standard Time or Mountain Daylight Time whichever is then in effect in the Northwest Territories;
- measure all quantities required to determine active energy and reactive energy transferred in the required directions at the metering point;
- provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the metering point;
- retain readings and, if applicable, all clock functions for at least fourteen (14) days in the absence of line power;
- have an accuracy class rating for active energy measurement that equals or exceeds the values specified in Appendix 3, Schedule 1, for non-dispensated metering equipment and Appendix 3, Schedule 2 for dispensated metering equipment;
- have an accuracy class rating for reactive energy measurement that equals or exceeds the values specified in Appendix 3, Schedule 1 for non-dispensated metering equipment and Appendix 3, Schedule 2 for dispensated metering equipment; and
- if the meter is internally compensated for line or transformer losses, shall have "LOSS COMPENSATED" indelibly marked in red on the nameplate.

6.3 Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers must:

- be Measurement Canada approved under subsections 9(1), 9(2) or 9(3) of the *Electricity and Gas Inspection Act*, as amended or replaced;
- be burdened to a degree that does not compromise the accuracy required by this Guideline; and
- have an accuracy class rating that equals or exceeds the values specified in Appendix 3, Schedule 1 for non-dispensated metering equipment.

6.4 Remote Communications Equipment

Remote communications equipment may or may not be an integral part of the meter or the recorder but must incorporate protocol schemes suitable for the type/nature of the communications media/path that will prevent the corruption of data during interval data transmission.

6.5 Quadrants to be Measured

DR Owners exporting power onto the Distribution System shall be equipped with bi-directional meters with four quadrant measurement capability. Six channels are required for four quadrant meters to separately record active power, leading power and lagging reactive power in both the export and the import directions. Where export of power is not required, unidirectional two quadrant metering with three channels is required to separately record active power, leading power and lagging reactive power. A reverse power relay shall also be installed to ensure blocking of any power exports.

6.6 Safety Requirements

The installation shall conform to the requirements of:

- Measurement Canada Standard Drawings;
- CSA Standard - C22.2; and
- ANSI/IEEE C57.13-1983 IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases.

7.0 INSPECTION AND TESTING

The DR Owner shall maintain a quality control and inspection program satisfactory to and approved by the Wires Owner.

In addition to the DR Owner's normal inspection procedures, the Wires Owner reserves the right to witness the manufacturing, fabrication or any part of work which concerns the subject equipment, to inspect materials, documents and manufacturing operations and installation procedures, to witness tests and to evaluate results of non-destructive examinations. The DR Owner shall supply the Wires Owner with a complete set of detailed drawings, which will be used by the Wires Owner to assist in the inspection during the testing of the equipment.

7.1 General

The DR Owner shall notify the Wires Owner in writing at least 2 weeks before the initial energizing and start-up testing of the DR equipment and the Wires Owner may witness the testing of any equipment and protective systems associated with the interconnection. The tests and testing procedures shall generally align with the requirements specified in IEEE P1547.

This section is divided into "type testing" and "verification testing". Type testing is performed or witnessed a single time by an independent testing laboratory for a specific protection package. Once a package meets the type test criteria described in this section, the design is accepted by the Wires Owner. If any changes are made to the hardware, software, firmware or verification test procedures, the manufacturer must notify the independent testing laboratory to determine what, if any, parts of the type testing must be repeated. Failure of the manufacturer to notify the independent test laboratory of changes may result in withdrawal of approval and disconnection of units installed since the change was made. Verification testing is site-specific, periodic testing to assure continued acceptable performance.

These test procedures apply only to devices and packages associated with protection of the interface between the generating system and the Wires Owner's facilities. Interface protection is usually limited to voltage relays, frequency relays, synchronizing relays, reverse current or power relays, and Anti-Islanding schemes. Testing of relays or devices associated specifically with protection or control of generating equipment is recommended, but not required unless they impact the interface protection.

Testing of protection systems shall include procedures to functionally test all protective elements of the system up to and including tripping of the generator and/or interconnection point. Testing will verify all protective set points and relay/breaker trip timing.

At the time of production, all interconnecting equipment and discrete relays shall meet or exceed the requirements of ANSI /IEEE C62.4 1 - 19 1 9-Recommended

Practices on Surge Voltages in Low Voltage AC Power Circuits or C37.90.1 1989, IEE standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems. If C62.41-1991 is used, the surge types and parameters shall be applied, as applicable, to the equipment's intended insulation location.

The manufacturer's verification test and the appropriate dielectric test specified in UL 174 1 shall also be met.

7.2 Type Testing

All interface equipment must include a type test procedure as part of the documentation. The type test must determine if the protection settings meet these guidelines.

Prior to testing, all batteries shall be disconnected or removed for a minimum of ten (10) minutes. This test is to verify the system has a non-volatile memory and that the protection settings are not lost. A test shall also be performed to determine that failure of any battery used to supply trip power will result in an automatic shutdown.

All inverters shall be non-Islanding as defined by IEEE 929. Inverters shall at the time of production meet or exceed the requirements of IEEE 929 and UL 1741.

7.3 Verification Testing

Prior to parallel operation of a generating system, or any time interface hardware or software is changed; a verification test must be performed. A licensed professional engineer or otherwise qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory trained and certified technicians, and licensed electricians with experience in testing protective equipment. The Wires Owner reserves the right to witness verification testing or require written certification that the testing was performed.

Verification testing shall be performed annually. All verification tests prescribed by the manufacturer or developed by the DR Owner, which are agreed to by the Wires Owner shall be performed. The DR Owner shall maintain verification test reports for inspection by the Wires Owner.

Inverter generator operation shall be verified annually by operating the load break disconnect switch and verifying that the DR Owner's facility automatically shuts down and does not restart for five minutes after the switch is closed as permitted in interconnection and operating agreements.

Any system that depends upon a battery for trip power shall be checked and logged once per month for proper voltage. Once every four years the battery must be either replaced or a discharge test performed and passed.

7.3.1 Protective Function Tests

Protection settings that have been changed after factory testing shall be field-tested. Tests shall be performed using secondary injection, applied waveforms, a simulated utility or, if none of the preceding tests can reasonably be done, a settings adjustment test, if the unit provides discrete readouts of the settings, to show that the device trips at the measured (actual) voltage and frequency.

The non-Islanding function, if provided, shall be checked by operating a load break switch to verify that the interconnection equipment ceases to energize its output terminals and does not restart for the required time delay after the switch is closed.

A reverse-power or minimum power function, if used to meet the interconnection requirements, shall be tested using secondary injection techniques. Alternatively this function can be tested by means of a local load trip test or by adjusting the DR output and local loads to verify that the applicable non-export criterion (i.e. reverse power or minimum power) is met.

7.3.2 Verification of Final Protective Settings Test

If protective function settings have been adjusted as part of the commissioning process, then, at the completion of such testing, the DR Owner shall confirm all devices are set to the Wires Owner's approved settings.

Interconnection protective devices that have not previously been tested as part of the interconnection system with their associated instrument transformers or that are wired in the field shall be given an in-service test during commissioning.

This test shall verify proper wiring, polarity, sensing signals, CT/VT ratios, and proper operation of the measuring circuits.

For protective devices with built-in metering functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values can be compared to the expected values. Alternatively, calibrated portable ammeters, voltmeters, and phase-angle meters may be used.

7.3.3 Hardware or Software Changes

Whenever interconnection system hardware or software is changed, the functions listed below may be affected. A retest shall be made of the potentially affected functions:

- over-voltage and under-voltage;
- over-frequency and under-frequency;

- non-islanding function (if applicable);
- reverse or minimum power function (if applicable);
- inability to energize dead line;
- time delay restart after the Wires Owner's outage;
- fault detection, if used; and
- synchronizing controls (if applicable).

To ensure that commissioning tests are performed correctly, it may be appropriate for the Wires Owner to witness the tests and receive written certification of the test results.

7.4 Switchgear and Metering

The Wires Owner reserves the right to witness the testing of installed switchgear, and metering. The DR Owner shall notify the Wires Owner at least ten days prior to any testing.

8.0 DATA REQUIREMENTS

The following lists the drawings and data required for the approval of the project:

Drawing/Data	Proposal	Approval*	Verified
Manufacturer' s Equipment Data Sheet			X
Control schematic		X	X
Single Line Diagram indicating proposed protection settings	X	X	X
Description of Protection Scheme	X	X	X
Generator Nameplate schedule		X	X
Fuse and protective relay coordination study & settings		X	X
Current transformer characteristic curve		X	X
Commissioning Report c/w Protection Settings			X
Plot plan showing location of lockable "visible" disconnect device	X	X	X

*The minimum time requirement for review of information will generally be in the order of 10 working days.

9.0 MARKING AND TAGGING

The nameplate on switchgear shall include the following information:

- manufacturer's name;
- manufacturer's serial number; and
- the disconnect switch shall be clearly marked "DG Disconnect Switch" and tagged with approved identification number from the Wires Owner.

10.0 MAINTENANCE

The DR Owner has full responsibility for routine maintenance of the DR Owner's generator, control and protective equipment and the keeping of records for such maintenance.

All of the equipment from the generator up to and including the visible point of isolation is the responsibility of the DR Owner. The DR Owner is responsible to maintain the equipment to accepted industry standards.

The DR Owner shall present the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment to the Wires Owner.

Failure to maintain CEC and industry acceptable facilities and maintenance standards can result in disconnection of the generator.

11.0 TABLES

Table 1

Protection for Single-Phase Generators

Interconnection Control, Protection and Safety Equipment	Single-Phase Connected to Secondary System	Inverter
Interconnect Disconnect Device	X	
Generator Disconnect Device	X	
Undervoltage Trip	X	
Overvoltage Trip	X	
Over & Under Frequency Trip	X	
Overcurrent	X	
Synchronizing Control	Manual or Automatic	
Synch-Check (At PCC)	X	
Anti-Islanding Protection		X

“X” denotes a requirement for this Guideline.

Notes:

1. Exporting to the Wires Owner system may require additional operational/protection devices and will require coordination of operations with the Wires Owner.
2. For synchronous and other types of generators with stand alone capability.
3. For single-phase generators larger than 50 kW, consult with the Wires Owner on the required interconnection control, protection and safety equipment.

Table 2

Protection for Three Phase Generators

Interconnection Control, Protection and Safety Equipment Three-Phase Connected to Primary or Secondary System

Device Number	Device	Generator Size Classification		
		<50 kW	50-499 kW	500-2,000 kW
	Interconnect Disconnect Device	X	X	X
	Generator Disconnect Device	X	X	X
	Synchronizing Control ¹ Manual (M) or Automatic (A)	M or A	M or A	A
25	Synch-Check ¹ (At PCC)	X	X	X
	Automatic Voltage Regulation (AVR) ¹		X	X
27	Undervoltage	X	X	X
59	Overvoltage	X	X	X
59N	Neutral Overvoltage ²	X ³	X	X
50/51	Instantaneous/Timed Overcurrent	X ⁴	X ⁴	X ⁴
50/51N	Instantaneous/Timed Neutral Overcurrent	X ³	X	X
81	Over & Under Frequency	X	X	X
32	Directional Power	X ⁵	X ⁵	X ⁵
TT	Transfer Trip or Equivalent Relay		X ⁶	X ⁶
	Telemetry Data Communication			X ⁷
	Anti-Islanding for Inverters (IEEE Std. 929, UL 1741)	X	X	X

“X” denotes a requirement for this guideline.

All devices are three-phase unless otherwise specified.

Notes:

For synchronous and other types of generators with stand alone capability.

1. Only required for generators that have their interconnection transformer's primary winding ungrounded. Used in conjunction with three PT's in broken delta configuration rated for line to line voltage. For detecting ground faults on the distribution system.
2. May not be required if the generator is an inverter type voltage-following system of less than 50 kW aggregate. In this case, the Wires Owner will inform the DR Owner if this protection is required.
3. A timed overcurrent relay with voltage restraint (51 V) may also be required to prevent nuisance trips.
4. Only required for non-exporting or export limited generators.
5. Transfer trip or equivalent protective relay function required for all synchronous generators rated 500 kW and larger with export capability. May also be required for exporting synchronous generators under 500 kW, depending upon characteristics of the distribution circuit. The Wires Owner will advise.
6. System controller requirement for all generators 5 MW and larger. The Wires Owner may also require telemetry for smaller generators depending upon location and distribution circuit characteristics.
7. Exporting to the Wires Owner's system may require additional operational/protection devices and will require coordination of operations with the Wires Owner.
8. Three directional overcurrent relays may be substituted for a reverse power relay.
9. Above to be in accordance with the *Canadian Electrical Code*.

Table 3

Protection for Closed Transition Switching

Interconnection Control, Protection and Safety Equipment Single-Phase Connected to Secondary System	
For 30 Cycles or Less (Closed Transition Switching)	
Interconnect Disconnect Device	X
Generator Disconnect Device	X
Undervoltage Trip	X
Overvoltage Trip	X
Over & Under Frequency Trip	X
Overcurrent	X
Neutral Overvoltage Trip ¹	X
Directional Power Trip	X
Synchronizing Control ²	Manual or Automatic
Synch-Check (At PCC) ²	X

“X” denotes a requirement for this Guideline.

Notes:

1. Selection depends upon grounding connection of interconnection transformer.
2. For synchronous and other types of generators with stand alone capability.

Appendix 1

Applicable Codes and Standards

The DR interconnection shall conform to this guideline and to the applicable sections of the following codes and standards. When the stated version of the following standards is superseded by an approved revision, then that revision shall apply.

Specific types of interconnection schemes, DR technologies, and Distribution Systems may have additional requirements, standards, recommended practices, or guideline documents external to this guideline. The applicability and hierarchy of those with respect to the requirements herein are beyond the scope of this guideline. Users of this guideline shall address those concerns. This list of standards is therefore not to be regarded as all-inclusive.

Power Quality Standards

- ANSI C84.1-1989 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 230 kV.
- IEEE Std. 493-1900 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book). Chapter 9 deals specifically with voltage sags analysis and methods of reporting sag characteristics graphically and statistically.
- IEEE Std 519-1992 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.
- IEEE Std. 1100-1992 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).
- IEEE Std 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality.
- IEEE Std 1250-1995 IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances.

In addition to the power quality standards, the following standards are applicable to the interconnection of distributed generation resources on the Wires Owner's system:

- IEEE Std. 100-1997 IEEE Standard Dictionary of Electrical and Electronics Terms
- IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3- 1975 (Reaffirmed 1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (Including Reference Designation Letters)
- IEEE Std 929-1988 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems
- C37.1 ANSVIEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automatic Control
- C37.2 IEEE Standard Electrical Power System Device Function Numbers
- C37.18 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery
- C37.20.1 ANSUIEEE Standard for Metal-Enclosed Low-voltage Power Circuit Breakers Switchgear
- C37.20.3 ANSUIEEE Standard for Metal-Enclosed Interrupter Switchgear
- C37.24 ANSUIEEE Standard for Radiation on Outdoor Metal-Enclosed Switchgear
- C37.27 ANSIIEEE Standard Application Guide for Low-voltage AC Nonintegrally Fused Power Circuit Breakers (Using Separately Mounted Current-Limiting Fuses)
- C37.29 ANSI/IEEE Standard for Low-voltage AC Power Circuit Protectors Used in Enclosures
- C37.50 ANSI Standard Test Procedures for Low-voltage AC Circuit Breakers Use In Enclosures
- C37.51 ANSI Standard Conformance Test Procedure for Metal Enclosed Low-voltage AC Power Circuit-Breaker Switchgear Assemblies
- C37.52 ANSI Standard Test Procedures for Low-voltage AC Power Circuit Protectors Used in Enclosures

- C57.12 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers
- C57.12.13 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.
- C57.13.1 IEEE Guide for Field Testing of Relaying Current Transformers
- C57.13.2 IEEE Standard Conformance Test Procedures for Instrument Transformers
- C37.58 ANSI Standard Conformance Test Procedures for Indoor AC Medium Voltage Switches for use in Metal-Enclosed Switchgear
- C37.90 ANSUIEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus
- C37.90.1 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- C37.90.2 ANSUIEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- C37.95 IEEE Guide for Protective Relaying of Utility Consumer Interconnections
- C37.98 ANSI/IEEE Standard for Seismic Testing of Relays
- IEC 1000-3-3 Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current less than 16A
- IEC1000-3-5 Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current greater than 16A
- UL1008 Transfer Switch Equipment
- IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems
- Canadian Electrical Code, CSA no. C22-1, latest version
- C22.2 No. 31-M89 (R1995) - Switchgear Assemblies

- CadCSA - C22.2 No. 107.1-95 - Commercial and Industrial Power Supplies
- CadCSA - C22.2 No. 1010.1-92 - Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use
- CadCSA - C22.2 No. 144-M91 (R1997) - Ground Fault Circuit Interrupters
- C22.2 No. 193-M1983 (R1992) - High Voltage Full-Load Interrupter Switches
- C22.2 No. 201-M 1984 (R1992) - Metal Enclosed High Voltage Busways
- C22.2 No. 229-M1988 (R1994) - Switching and Metering Centres
- CSA Standard CAN3 C235 83 - Preferred Voltage Levels for AC Systems 0 to 50,000V
- *Alberta Electrical and Communication Utility Code, 2nd Edition, 2002, declared in force pursuant to the Electrical Code Regulation, Alta. Reg. 145/2002*
- C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD)
- C37.04i-1991 Supplement to IEEE C37.04-1979
- C37.06-1997 American National Standard for Switchgear-AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis—Preferred Ratings and Related Required Capabilities
- C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD)
- C37.09a-1991 Supplement to IEEE C37.09-1979
- C37.09g-1991 (R1991) Supplement to IEEE C37.09-1979
- C37.010-1999 IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
- C37.010b-1985 (R1988) Supplement to IEEE C37.010-1979
- C37.010e-1985 (R1988) Supplement to IEEE C37.0 10-1979 I Supersedes:

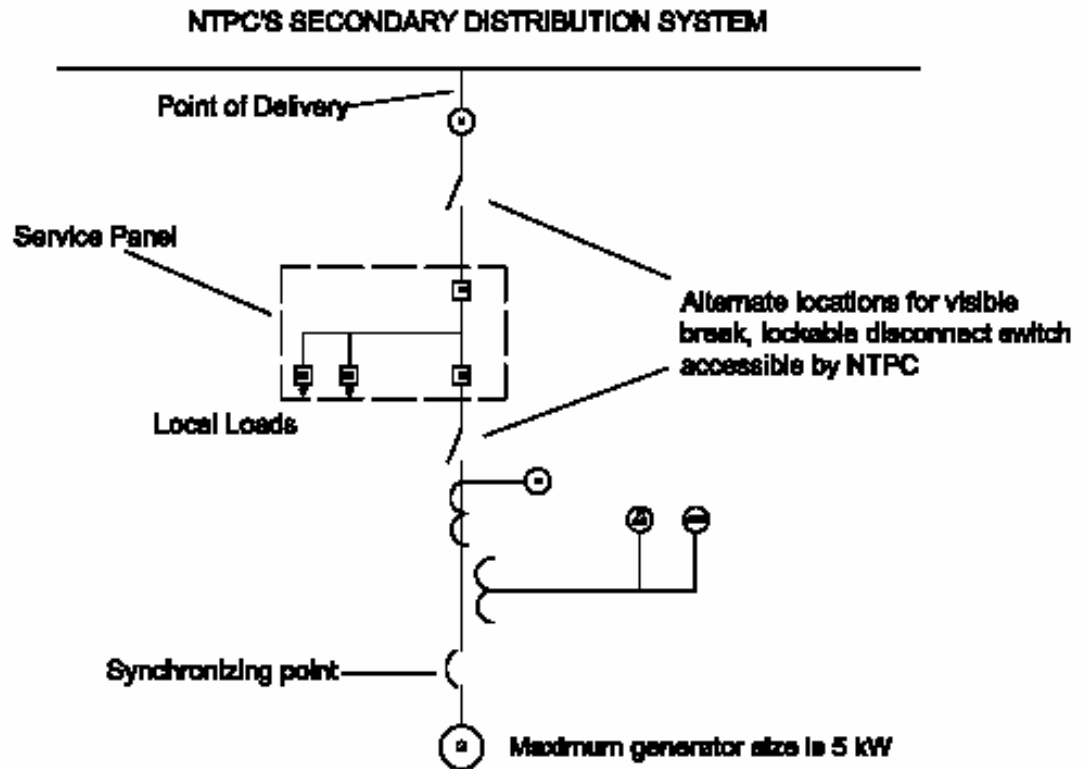
- C37.0 11-1994 IEEE Application Guide for Transient Recovery Voltage for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
- C37.012-1979 (R1988) IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
- C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis
- C37.015-1993 IEEE Application Guide for Shunt Reactor Switching
- C37.081-1981 (Reaff 1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current basis
- C37.11-1997 IEEE Standard Requirements for Electrical Control for High-Voltage Circuit Breakers Rated on A Symmetrical Current Basis
- C37.13-1990 (R1995) IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures
- C37.14-1992 IEEE Standard for Low-Voltage DC Power Circuit Breakers Used in Enclosures
- C37.16-1997 American National Standard for Switchgear - Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors - Preferred Ratings, Related Requirements, and Application Recommendations
- C37.20.2-1999 IEEE Standard for Metal-Clad and Station-Type Cubicle switchgear
- C37.20.2b-1994 Supplement to IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear: Current Transformer Accuracies
- C37.20.6-1997 IEEE Standard for 4.76 to 38kV Rated Grounding and Testing Devices used in Enclosures
- C37.23-1987 (R1991) IEEE Standard for Metal-Enclosed Bus and Calculating Losses in Isolated-Phase Bus
- C37.30-1997 IEEE Standard Requirements for High-Voltage Switches

- C37.32-1996 American National Standard for Switchgear—High-Voltage Air Switches, Bus Supports, and Switch Accessories—Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide
- C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches
- C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches
- C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches
- C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V)
- C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches
- C37.42-1996 American National Standard for Switchgear—Distribution Cutouts and Fuse Links—Specifications
- C37.44-1981 (R1987) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links
- C37.54-1996 American National Standard for Switchgear—Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies—Conformance Test Procedures
- C37.55-1989 American National Standard for Switchgear—Metal-Clad Switchgear Assemblies--Conformance Test Procedures
- C37.57-1990 American National for Switchgear—Metal-Enclosed Interrupter Switchgear Assemblies—Conformance Testing
- C37.66-1969 (Reaff 1988) American National Standard for Requirements for Oil-Filled Capacitor Switches for Alternating-Current Systems
- C37.81-1989 (R1992) IEEE Guide for Seismic Qualification of Class 1E Metal-Enclosed Power Switchgear Assemblies

- C37.85-1989 (R1998) American National Standard for Switchgear—Alternating-Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X-Radiation Limits
- ANSI/IEEE C37.90-1989 - Surge Withstand And Fast Transient Tests
- 120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits
- 1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear Application Guide for Surge Protection of Electric Generating Plants - IEEE Std
- C62.23-1995 (37.13-1993 IEEE Standard Requirements for Instrument Transformers.
- C57.13.3-1983 (R1991) IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases
- C57.98-1993 IEEE Guide for Transformer Impulse Tests
- C57.19.100-1995 (R1997) IEEE Guide for Application of Power Apparatus Bushings
- C57.1 10-1986 (R1992) IEEE Recommended Practice for Establishing Transformer Capability When Supplying Nonsinusoidal Load Currents
- C62.92.4-1991 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV - Distribution
- ANSI C12.20 - Electricity Meters 0.2 And 0.5 Accuracy Classes
- ANSI C62.1 - Surge Arresters for AC Power Circuits
- ANSI C62.11 - Metal-Oxide Surge Arresters for AC Power Circuits
- NEMA CC-1 - Electric Power Connectors for Substations
- NEMA LA-1 - Surge Arresters
- NEMA MG- 1 - Motors

Appendix 2

Typical Arrangements



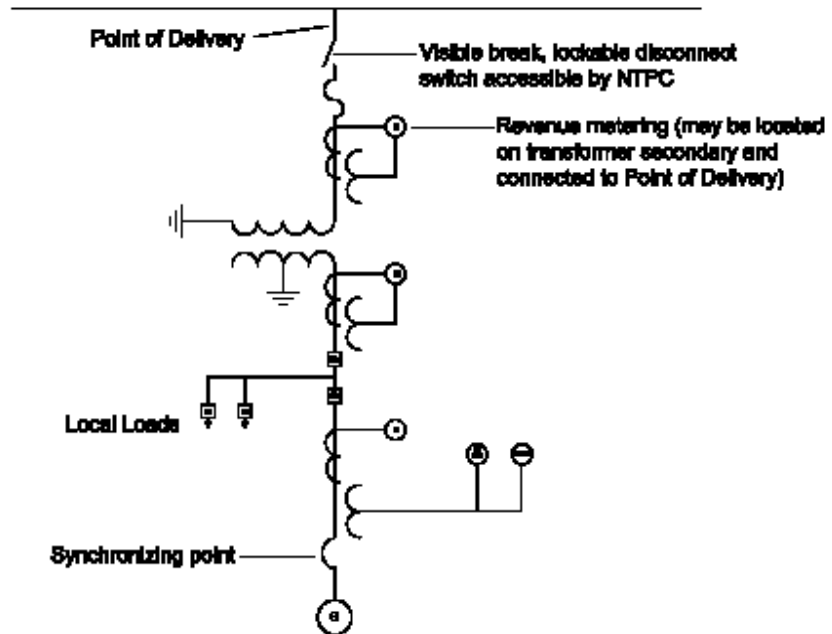
Protection Functions

52	Circuit Breaker
51	Overcurrent protection
81O/U	Over / under frequency protection
27/59	Under / over voltage protection
M	Revenue metering

Note: Typical requirements shown. DG shall evaluate requirements for further protection

**FIGURE #1
TYPICAL SINGLE PHASE GENERATOR INSTALLATION CONNECTED TO NTPC'S SECONDARY SYSTEM**

NTPC'S PRIMARY DISTRIBUTION SYSTEM



Protection Functions

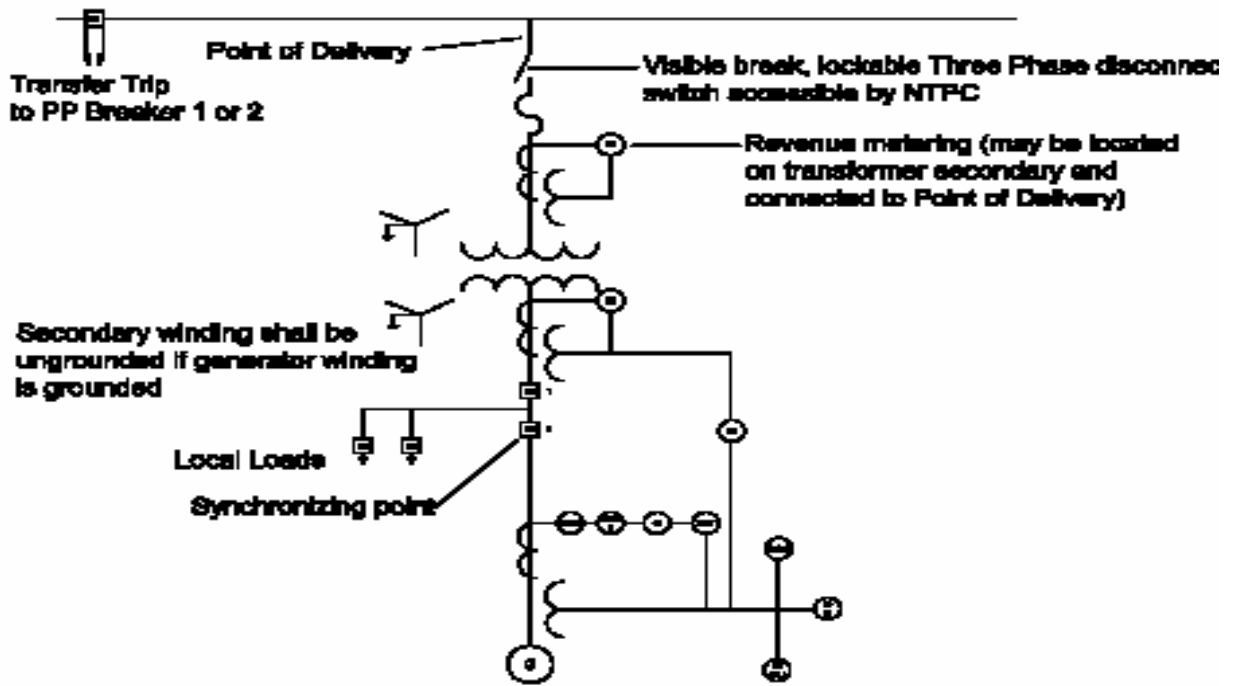
52	Circuit Breaker
51	Overcurrent protection
32	Reverse Power protection (required if customer does not purchase stand-by)
81Q/U	Over / under frequency protection
27/59	Under / over voltage protection
M	Revenue metering

Note: Typical requirements shown. DG shall evaluate requirements for further protection

**FIGURE #2
TYPICAL SINGLE PHASE NON SYNCHRONOUS GENERATOR INSTALLATION
UP TO 50 KW**

(b)

NTPC'S PRIMARY DISTRIBUTION SYSTEM



Protection Functions

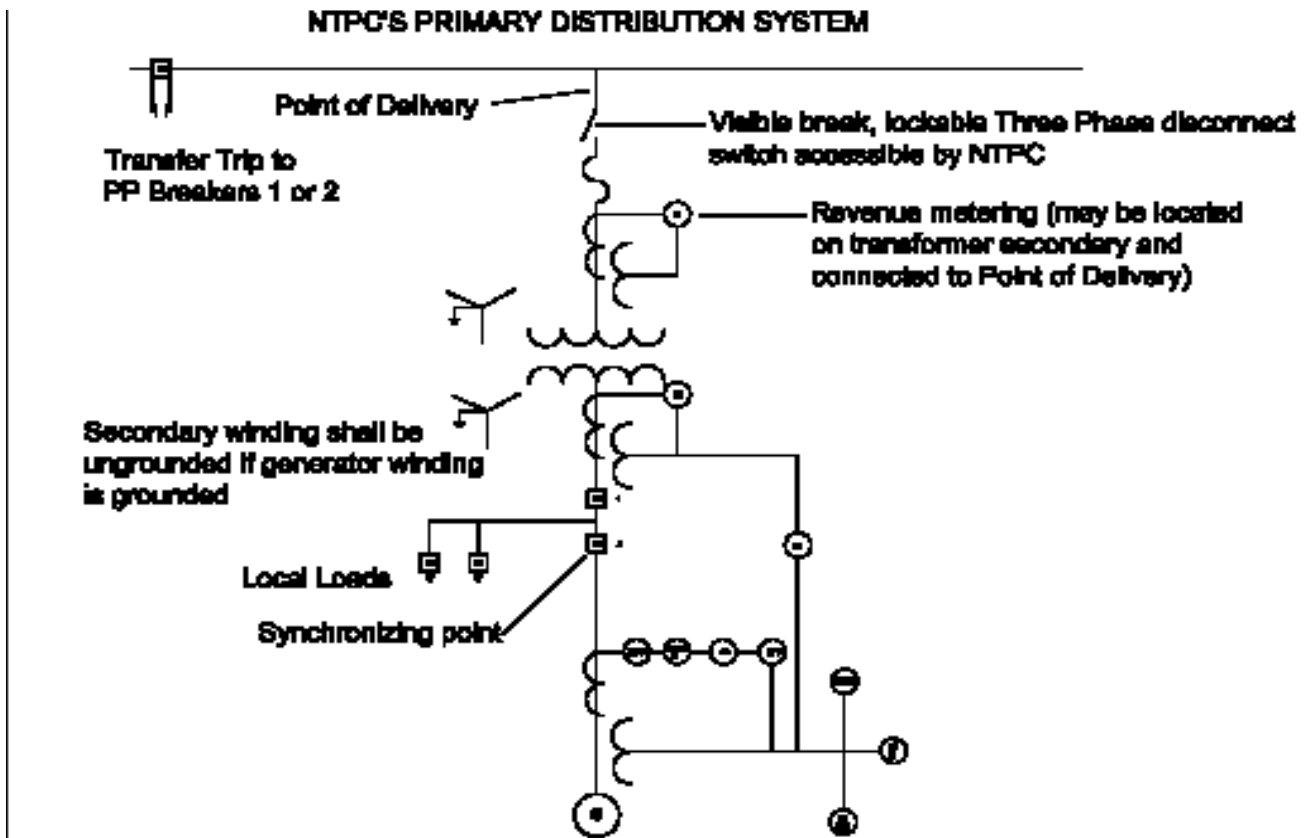
- 82 Circuit Breaker
- 50/51 Instantaneous/Timed Overcurrent
- 50/51N Instantaneous/Timed Neutral Overcurrent
- 51V Voltage restraint overcurrent protection
- 32 Reverse Power protection
- 61OVU Over / under frequency protection
- 27/59 Under / over voltage protection
- 59 N Neutral Overvoltage
- 46 Phase unbalance protection
- 25 Synch - Check
- M Revenue metering

Note: Typical requirements shown. DG shall evaluate requirements for further protection

**FIGURE #3
TYPICAL THREE PHASE NON SYNCHRONOUS GENERATOR INSTALLATION
UP TO 50 KW**



(c)



Protection Functions

52	Circuit Breaker
50/51	Instantaneous/Timed Overcurrent
50/51N	Instantaneous/Timed Neutral Overcurrent
51V	Voltage restraint overcurrent protection
32	Reverse Power protection
81Q/U	Over / under frequency protection
27/58	Under / over voltage protection
58 N	Neutral Overvoltage
46	Phase unbalance protection
25	Synch - Check
M	Revenue metering

Note: Typical requirements shown. DG shall evaluate requirements for further protection

**FIGURE #4
TYPICAL THREE PHASE NON SYNCHRONOUS GENERATOR INSTALLATION**

Appendix 3

Schedule 1

Schedule of Accuracies for Metering Equipment Approved Under Section 9(1) of the *Electricity And Gas Inspection Act*

Metering Point Capacity (MVA)	Watt-hour Meter Accuracy Class	Varhour Meter Accuracy Class	Measurement Transformers Accuracy Class
10 and Above	0.2%	0.5%	0.3%
Below 10	0.5%	1.0%	0.3%

Notes:

1. The columns apply to requirements set out in the Metering Section.
2. If an alternate measurement is used to determine reactive energy, the accuracy class of the alternate measurement must be equal to or better than the accuracy class set out for reactive energy

Schedule 2

Schedule of Accuracies for Meters Approved Under Subsections 9(2) or 9(3) of the *Electricity And Gas Inspection Act*

Meter Accuracy		
Metering Point Capacity (MVA)	Points of Delivery	Points of Supply
10 and Above	1.0%	1.0%
Below 10	1.0%	1.0%

Notes:

1. The columns apply to requirements set out in the Metering Section.
2. If an alternate measurement is used to determine reactive energy, the accuracy class of the alternate measurement must be equal to or better than the accuracy class set out for reactive energy

Appendix 4

Notes

Note 1:

- (a) Refer to “Chapter 11, Connecting Small Generators to Utility Distribution Systems” by A.B. Sturton.
- (b) Refer to “Transformer concepts and application course notes” by Power Technologies Inc., Schenectady, New York.
- (c) Refer to “Electrical Transients in Power Systems” by Allan Greenwood.
- (d) Refer to “Electrical Transmission & Distribution Reference Book” by Westinghouse.

Note 2:

- (a) Refer to “Protective Relaying, Principles and Applications” by J. Lewis Blackburn on details on sub-synchronous resonance.
- (b) Refer to “Electrical Transmission & Distribution Reference Book” by Westinghouse.

Note 3:

- (a) Refer to “Chapter 8, Harmonic and Resonant Effects on Application of Capacitors, Distribution Systems, Electric Utility Reference Book by Westinghouse.
- (b) Refer to “Chapter 11 & 12, Connecting Small Generators to Utility Distribution Systems” by A.B. Sturton.
- (c) Refer to “Chapter 10, Electric Power Systems, on switching surges-interruption of capacitive circuits by B.M. Weedy.

Note 4:

- (a) Refer to “Chapter 4, Connecting Small Generators to Utility Distribution Systems” by A.B. Sturton.

1 **APPENDIX E: ILLUSTRATIVE COST-OF-SERVICE**

2 As discussed in Section 1, the Corporation is taking a simplified approach to this Phase II
3 Application. This approach benefits customers by:

4 1. Avoiding the cost to customers of a full Phase II proceeding when there is limited
5 ability (due to the 15% cap on base rate plus shortfall rider adjustments) to rebalance
6 rates between customers and communities.

7 2. Simplifying rate adjustments so that base rates are predominantly the same as those
8 established January 1, 2008 and rate adjustments at this time are linked to temporary
9 stabilization fund and shortfall riders.

10 3. Addressing fairness to future customers by collecting costs related to previous years
11 in a timely way.

12 As a result of this simplified approach to Phase II, the Corporation is not addressing
13 changes to its cost-of-service method and rate design that it might otherwise propose.
14 Certain Board directives related to cost-of-service methods also are not addressed.
15 However, the Corporation considers that this approach is prudent and in the best interest of
16 customers.

17 Schedule E provides a summary of an illustrative cost-of-service study for the 2007/08 test
18 year. Revenue requirement, miscellaneous revenues and sales (kW.h) have been updated
19 to reflect the 2007/08 approved values. The study uses the same methods approved for the

1 Corporation's 2002/03 Phase II General Rate Application in Board Decision 8-2003. The
2 Corporation is not seeking approval of the cost-of-service method or the results of the study,
3 since there is very limited rate rebalancing that can be undertaken between communities
4 and rate classes at present. Instead, the Corporation is providing this summary information
5 for illustrative purposes only. The illustrative results indicate that most communities and rate
6 classes are within the range of 95% to 105% RCC, or are already facing base rate
7 adjustments plus shortfall rider increases of 15%.

8 The revenues by rate-class and community reflect the proposed energy rates outlined in
9 Schedule 1.1. As discussed in Section 1, those proposed rates reflect only very limited rate
10 rebalancing in the two Hydro zones. For those systems, Dettah and Fort Resolution both
11 have Revenue to Cost Coverage ("RCC") ratios that are substantially below 100% as
12 shown in Schedule E. Other customer classes and communities on those systems have
13 RCC ratios over 100%. Accordingly, the Corporation raised the proposed base energy rates
14 in those communities such that the increase in base energy rates plus the increase in the
15 proposed shortfall rider resulted in a 15% increase in Dettah and Fort Resolution. This
16 allowed proposed energy rates for the Wholesale and Industrial customers on the
17 Snare/Yellowknife and Taltson systems to be lowered slightly. No adjustments to base rates
18 were proposed for Behchoko or Fort Smith, since the RCC ratios in those communities are
19 lower than for the Wholesale and Industrial customers on those systems.

**NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule E: 2007/08 COSA Summary**

Based on rates with brushing adjustment

Plant No.		General					Total (\$000)	Comparison to COS		
		Residential (\$000)	Service (\$000)	Streetlighting (\$000)	Wholesale (\$000)	Industrial (\$000)		COS (\$000)	Difference (\$000)	Revenue: Cost Coverage
		A	B	C	D	E	F	G	H	I
1	104 Wha Ti	723	589	28			1,340	1,321	19	101.5%
2	105 Gameti	530	534	24			1,088	1,063	25	102.4%
3	108 Behchoko	954	929	53			1,936	1,923	13	100.7%
4	109 Dettah	178	87	9			274	319	-45	85.9%
5	110 Lutsel K'e	571	503	36			1,109	1,076	33	103.0%
6	201 Fort Smith	1,694	1,740	60			3,495	3,387	108	103.2%
7	203 Fort Resolution	314	244	22			580	1,123	-543	51.7%
8	205 Fort Simpson	1,711	2,244	79			4,034	5,176	-1,142	77.9%
9	206 Fort Liard	649	784	47			1,480	1,683	-204	87.9%
10	207 Wrigley	286	376	45			707	877	-170	80.6%
11	208 Nahanni Butte	191	261	23			475	632	-157	75.2%
12	209 Jean Marie River	131	179	24			334	483	-149	69.2%
13	301 Inuvik	5,264	9,145	163			14,572	14,042	530	103.8%
14	304 Norman Wells	1,239	1,965	63			3,267	3,174	92	102.9%
15	305 Tuktoyaktuk	1,518	1,099	64			2,681	2,634	46	101.8%
16	306 Fort McPherson	1,176	1,070	48			2,295	2,243	51	102.3%
17	307 Aklavik	883	779	48			1,710	1,666	44	102.6%
18	308 Deline	924	880	22			1,826	1,768	58	103.3%
19	309 Fort Good Hope	908	865	47			1,820	1,805	15	100.8%
20	310 Tulita	939	734	36			1,709	1,678	31	101.9%
21	311 Paulatuk	630	747	32			1,409	1,360	49	103.6%
22	312 Sachs Harbour	363	613	45			1,021	1,000	21	102.1%
23	313 Tsiigetichic	424	366	30			820	806	15	101.8%
24	314 Colville Lake	365	294	34			693	664	29	104.4%
25	315 Ulukhaktok	618	683	24			1,325	1,334	-9	99.3%
26	Wholesale NUL-Yellowknife				25,194		25,194	24,552	642	102.6%
27	Wholesale NUL-NWT				2,511		2,511	1,929	582	130.2%
28	Industrial - Miramar Con					549	549	535	14	102.6%
29	Industrial - Miramar Giant					549	549	535	14	102.6%
30	Totals	23,185	27,710	1,105	27,705	549	80,254	80,255		
Comparison to COS										
31	COS	25,007	27,212	1,006	26,480	535				
32	Difference	-1,822	498	99	1,225	14				
33	Revenue:Cost Coverage	92.7%	101.8%	109.8%	104.6%	102.6%				

Notes:
 1. Head Office and Area Office allocation assume the same as 2002/03 COSA.
 2. Transmission allocation assume the same as 2002/03 COSA

1 **APPENDIX F: RESPONSES TO BOARD DIRECTIVES**

2 This section sets out NTPC's responses to Directives issued to NTPC by the PUB as part of
3 or since the 2001/03 GRA. Several technical cost-of-service study directives are not
4 addressed at this time, as NTPC has not undertaken a full cost-of-service study in support of
5 this application. These directives include:

6

- 7 • Directive 2 from Decision 7-2003 respecting the definition of legacy assets.
- 8 • Directive 3 from Decision 7-2003 respecting cost of service studies for Behchoko
9 (formerly Rae/Edzo) and Dettah.
- 10 • Directive 3 from Decision 17-2007 respecting the benefits of AMR being reflected in
11 the cost-of-service study.

12 NTPC will address those directives at the time of its next full Phase II application.

13

14 **Decision 3-2003 – Directive 10:**

15 **The Board directs NTPC to investigate the benefits and market potential for time of**
16 **use rates and address this matter at the time of the next GRA.**

17

18 Generally, time-of-use rates are beneficial to utilities and customers on a system where the
19 cost of generation and transmission varies considerably by day or season. Often this occurs
20 in an interconnected system where import costs or export sales vary, sometimes

1 dramatically, on a seasonal or hourly basis. For example, in an interconnected hydro-electric
2 system such as Manitoba or Quebec, the cost to import power in the middle of the night may
3 be very very low, one cent per kW.h or less, while the cost to import power in the afternoon
4 during the summer cooling or winter heating season might be dramatically higher. On these
5 types of systems there may be benefits to pricing that differs by time of day or season as it
6 passes those price signals on to consumers who can then make economically efficient
7 consumption decisions. By contrast, the Corporation does not have an integrated electricity
8 market and its generation costs do not vary appreciably by time of day or season.

9

10 The Corporation has considered the potential benefits of time of use rates on its own
11 systems and determined that it would not be beneficial to pursue time of use rates at this
12 time for several reasons:

13

- 14 • At present, both the Snare/Yellowknife and Taltson hydro systems have very limited
15 diesel generation requirements, related largely to times of hydro unavailability. These
16 times are hard to predict and are not related to seasonal or daily use patterns,
17 therefore there is little or no benefit to customers of shifting loads between daily or
18 season periods. When diesel generation is required more frequently a time-of-use
19 rate structure may have more potential benefits.
- 20 • Similarly, in the thermal communities the Corporation's generation costs do not vary
21 by daily or seasonal periods as they might in an interconnected system. Generation

1 facilities are planned to meet the annual system peak. As a result there is little to no
2 benefit in the thermal communities of shifting load between daily or seasonal periods.

3

4 While there would be little to no cost savings as a result of time-of-use rates, there would be
5 added costs including:

6

- 7 • Metering technology to accommodate time-of-use rates.
- 8 • While the Corporation's current billing system can accommodate time-of-use
9 rates, implementing those rates would require writing a new billing software script.

10

11 As a result, the Corporation is not proposing time-of-use rates at this time. The Corporation
12 believes it is more prudent for its customers to focus on general conservation efforts, to
13 reduce bills and generation requirements at any time of the day or season of the year, rather
14 than develop a new rate structure that would be difficult or costly to implement. The
15 Corporation believes there are substantial benefits to customers, given the current rate
16 structure, to pursue these types of conservation initiatives.

17

18 With respect to future directions on the topic of time-of-use rates, the Corporation, in
19 conjunction with Northland Utilities, has proposed a meeting with the Board to discuss the
20 future directions on this topic.²³

21

²³ Letter from Northwest Territories Power Corporation and Northland Utilities to the Northwest Territories Public Utilities Board dated August 8, 2008.

1 **Decision 13-2007 – Directive 23:**

2 **The Board directs NTPC, in its Phase 2 application, to include this proposed change**
3 **to Section 13.2 of the Terms and Conditions of Service to give interveners and**
4 **customers the opportunity to respond to it.**

5

6 The Corporation has attached a copy of the Terms and Conditions of Service with revisions
7 (blacklined) to Section 13.2 as well as related revisions to section 4.1 and section 14.1
8 consistent with the comments of the Board in Decision 13-2007.²⁴ The nature of the
9 revisions are:

- 10 1. To remove from Section 4.1 the provision for the Corporation to refuse to provide
11 service if a former customer residing at the premises has existing arrears.
- 12 2. To restate the limitations on the Corporation's limitation of liability (Section 13.2) and
13 Indemnity (Section 14.1), considering the comments of the Hydro Communities
14 during the 2006/07 & 2007/08 Phase I proceeding and consistent with the
15 Corporation's Reply Argument in that proceeding.²⁵

16

17 **Decision 13-2007 – Page 151**

18 **The Board notes none of the parties raised any issues respecting the (Standby**
19 **Interconnection) guidelines. The Board has reviewed the guidelines and approves**
20 **them on an interim basis for purposes of this Decision. The Board will examine the**

²⁴ Page 148-151 of Decision 13-2007.

²⁵ NTPC Reply Argument dated July 3, 2007. Pages 40-41.

1 **guidelines together with associated rates at the time of the Phase 2 proceedings and**
2 **consider final approval at that time.**

3
4 The response to this directive is addressed in Appendix D of this application.

5
6 **Decision 20-2007 – Page 5:**

7 **For the purposes of calculating the Board-determined 2006/07 under recovery rider,**
8 **the Board has prorated the \$2.085 million amount to each of the communities on the**
9 **basis of the unrecovered balance as of March 31, 2007 and used the 2007/08 volumes**
10 **to arrive at the rider amount by community. These calculations are shown in**
11 **Schedule 1 of Appendix 2. The Board expects its estimates would result in a**
12 **reasonable 2006/07 rider by community intended to recover the 2006/07 unrecovered**
13 **amounts as of December 31, 2007 over a 12 month period, for purposes of interim**
14 **rates. However, since these are estimates, NTPC is directed to update the 2006/07**
15 **unrecovered balances by community at the time it files its application for recovery of**
16 **the 2007/08 revenue under recoveries and incorporate all revenue under recovery**
17 **amounts at that time into a single rider.**

18
19 The response to this directive is addressed in Appendix B of this application. The shortfall
20 riders currently in place would recover the 2006/07 shortfall balances within approximately
21 the 12 month period anticipated by the Board. However there are balances related to the
22 2007/08 shortfalls that would require considerably longer to recover at the present shortfall
23 rider levels.

1 **Decision 20-2007 – Page 6:**

2 **On the basis of the information provided, the Board is prepared to accept the fuel**
3 **stabilization riders for purposes of establishing interim rates. However, since the fuel**
4 **stabilization rider calculations were not subject to full examination as part of these**
5 **proceedings, NTPC is directed to provide detailed schedules showing how the**
6 **proposed fuel riders were arrived at having regard to the underlying GRA forecast**
7 **and the go forward fuel cost estimates for each of the funds at the time of the Phase II**
8 **application.**

9

10 The response to this directive is addressed in Appendix C of this application.

DRAFT TERMS & CONDITIONS OF SERVICE



TERMS & CONDITIONS OF SERVICE

Effective Date: XXXXXXX

DRAFT TERMS & CONDITIONS OF SERVICE

NORTHWEST TERRITORIES POWER CORPORATION

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DRAFT TERMS & CONDITIONS OF SERVICE

TERMS AND CONDITIONS OF SERVICE

1.0 Introduction

1.1 Approval:

In accordance with the *Northwest Territories Power Corporation Act* R.S.N.W.T. 1988, c. N-2 and the *Public Utilities Act* N.S.N.W.T 1988, c.24, these Terms and Conditions of Service (hereinafter referred to as "Terms") have been approved by the Public Utilities Board of the Northwest Territories (hereinafter referred to as the "Board"), and may not be changed without the approval of the Board.

1.2 Effective Date:

These Terms come into force 60 days following the date of the Board's order and replaces all previous versions Corporation's Terms. Whenever the Board approves an amendment, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

1.3 Conflicts:

If there is any conflict between a provision expressly set out in an Order of the Board and the Terms, the Order of the Board shall govern.

1.4 Headings:

The division of the Terms into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of the Terms.

1.5 Extended Meanings:

In the Terms, words importing single number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neutral genders and vice versa and words importing a person shall include an individual, firm, partnership, association, trust, unincorporated organization, corporation Municipal Corporation, trustee or executor.

DRAFT TERMS & CONDITIONS OF SERVICE

1.6 Statutes:

Unless otherwise specifically indicated, all references to statutes include amendments thereto, as well as all regulations, standards and guidelines established pursuant to that statute.

1.7 Schedules:

The following schedules are attached to and form part of the Terms:

Schedule "A" – Maximum Corporation Investment

Schedule "B" – Conditions of Underground Service

Schedule "C" – Fees and Service Charge Summary

2.0 **Definitions**

The following words or phrases, when used in these Terms and Conditions of Service, or Customers' Application(s) for Service shall, unless the context otherwise requires, have the following meanings:

2.1 Applicant:

Means any person which requests Service from the Corporation.

2.2 Billing Adjustment:

Means the correction of a prior over or under-billing.

2.3 Billing Demand

Means the Demand upon which billing to a Customer is based and may be estimated or measured by an approved Demand Meter. Unless otherwise specified in the Demand for the current billing period or the maximum Demand experienced during the 12-month period ending with the current billing period for determination of Demand Charges, the Billing Demand shall not be less than 5 kW per month. All references in the Rate Schedules to a measurement in "kW" at a particular rate shall be deemed to include a reference to "kVA" measured at the same rate and vice versa.

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2.4 Connected Load:

Means the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

2.5 Construction Contribution:

The difference between the capital cost incurred by the Corporation by installing the Corporation's Facilities to serve a Customer and the Maximum Corporation Investment specified in Schedule A.

2.6 Corporation:

Means the Northwest Territories Power Corporation and any of its employees, agents, or contractors.

2.7 Corporation Facilities:

Means physical plant owned or leased by the Corporation including, without limitation, electrical energy production plant, transmission and distribution systems, transformers, meters, equipment and machinery used in the production transmission and distribution of Energy.

2.8 Customer:

Means any person to whom Service is being or has been provided, whether or not:

- a) the person did not request Service from the Corporation; or
- b) the name or signature of the person appears on a written application for Service or contract of Service

and includes an Applicant to which the Corporation has decided to commence providing Service.

2.9 Customer Charge/Service Charge:

Means that portion of the charge for Service, excluding any Facilities Charge, which does not vary with the level of Demand or Energy consumption. This charge is

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assessed to partially offset the various fixed costs associated with the provision of Service such as service lines, meter reading and billing of accounts.

2.10 Customer Facilities:

Means the equipment to be supplied by the Customer to allow for the attachment of Corporation Facilities for the delivery of Energy to the Customer, installed in accordance with applicable statutes, regulations, standards and codes.

2.11 Customer Service Order (CSO):

Means an agreement for the provision of a Service pursuant to these Terms and Conditions of Service, between the Corporation and the Customer.

2.12 Demand:

Means the rate at which, electric Energy is delivered from the Corporation Facilities to a Customer expressed in kilowatts (kW), kilovoltamperes (kVA) or other suitable unit, at a given instant or averaged over any designated period of time.

2.13 Demand Charge:

Means that portion of the charge for Service based upon the electric Demand (measured in units of kW or kVA) consumed and billed on the basis of Billing Demand at the applicable rate.

2.14 Electricity:

Means electric power, and includes both Energy and Demand.

2.15 Energy: Means, as the context requires:

- a) electric energy expressed in kilowatt-hours (kWh); and
- b) thermal (heat) energy which is supplied to or through a heating system by hot water, hot air, steam or glycol expressed in kilowatt-hours (kWh_T) or gigajoules (Gj).

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2.16 Energy Charge:

Means that portion of the charge for Service based upon the Energy consumed or billed.

2.17 Facilities Charge:

Means all sums not collected through Demand Charges, Energy Charges, and Customer Charges charged to a Customer's account to recover:

- a) the costs associated with the dedication of Corporation Facilities to that Customer;
- b) all other charges arranged by agreement with the Customer, other than Energy Charges, Demand Charges and Customer Charges.

2.18 General Service:

Means a classification of Service referring to other than Residential, Industrial, Wholesale, Municipal Street Lighting and Private Area Lighting Service. This classification also includes, without limitation:

- a) service provided to a Government Customer;
- b) a single family dwelling where a business is carried on within the dwelling and the entire dwelling is supplied through one meter,
- c) a common use area associated with a group of residential dwellings (for example, utility rooms), and
- d) a multiple unit dwelling supplied through one meter.

2.19 Gigajoule (GJ):

Means the standard unit of energy in the SI or metric system of measurement.

2.20 Government Customer:

Means a Customer whose account for Service is payable or funded by a federal, territorial or municipal authority, or whose function is to provide on behalf of or to the public:

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- a) executive, legislative and other general government support services; or
- b) justice, public order, postal, or safety services; or
- c) administration of: human resource programs; environmental quality or compliance programs; housing programs; health care programs; social assistance programs; urban planning services; community development programs; economic programs; or educational programs; or
- d) space research and technology services; or
- e) territorial or national security or international affairs services, but does not include a User Pay Customer.

2.21 Industrial:

Means a classification referring to a business, the primary business of which is resource exploration, development or mining, and includes, but is not limited to, the construction, operation, reclamation or shut down phases of such business.

2.22 Interruptible Service:

Means Electric Service provided by the Corporation to a Customer under agreements, which permit curtailment or cessation of delivery by the Corporation.

2.23 Joint Use Service:

Means the provision by the Corporation of leased space on existing Corporation transmission and distribution poles, where sufficient space is available, to electrical and communication utilities in areas in which the Corporation provides Service.

2.24 Load Factor:

Means the ratio of the average demand (in kW) supplied during a designated period to the peak or maximum load (in kW) occurring in the period. When expressed as a percentage, Load Factor during a period is the ratio of total energy consumed during the period (in kWh) to the maximum load (in kWh) during the period.

2.25 Maximum Corporation Investment:

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Means the available Corporation investment in dollars as set out in Schedule A.

2.26 Multiple Unit Dwelling :

Means a residential building containing more than one residential dwelling unit.

2.27 Municipal Corporation:

Means a corporation established or continued as a city, town, village, hamlet or charter community by or under the *Cities, Towns and Villages Act*, R.S.N.W.T. 1988, c. C-8, *Charter Communities Act*, R.S.N.W.T. 1988, c. C-4 or *Hamlets Act*, R.S.N.W.T. 1988, c. H-1.

2.28 Municipal Street Lighting Service:

Means a classification referring to the supply of Electricity to municipal street lighting by the Corporation in communities serviced by the Corporation and includes, without limitation, the installation, operation and maintenance of standard street lighting luminaires on wood poles and serviced by overhead wiring.

2.29 Point of Delivery:

Means, unless otherwise specified in an accepted application for Service or an agreement or contract, the point at which the Facilities required to provide Service are connected to Customer Facilities

2.30 Primary Service:

Means service of Electricity provided by the Corporation at primary voltage levels to an end-use Customer, with all secondary transformation and distribution provided by the Customer.

2.31 Private Area Lighting Service:

Means Service involving the supply of Electricity to off-street and area lighting by the Corporation in communities serviced by the Corporation and may include the purchase, installation and energizing of the area lighting.

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2.32 Rate Schedules:

Means the schedules of regulated rates prepared by the Corporation pursuant to the *Public Utilities Act*, as amended from time to time.

2.33 Residential Service:

Means Service to a detached single family dwelling or an individual unit in a multiple unit dwelling where Service is provided to the unit through a single meter, which does not serve another unit in the multiple unit dwelling. To be classified as Residential the detached single family dwelling or individual unit in a Multiple Unit Dwelling must be used exclusively as a residence and must not be used for Industrial, Wholesale, or General Service purposes.

2.34 Seasonal Service:

Means Service that in the sole opinion of the Corporation acting reasonably is anticipated to be repeatedly connected and disconnected at the Customer's request on a seasonal basis.

2.35 Service:

Means the delivery of Energy or the making available of Energy for delivery at the Point of Delivery.

2.36 Short Term Temporary Service:

Means Service that in the sole opinion of the Corporation acting reasonably will be required for a period of 12 months or less, and subsequently will not be required again for a period of at least 12 months.

2.37 Temporary Construction Service:

Means Service provided during the construction or renovation of a building by way of a meter situated in a temporary location.

2.38 TMI:

Means a Time and Materials Invoice used to bill for costs incurred for work

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undertaken by the Corporation in relation to a maintenance agreement or other arrangement between a Customer and the Corporation.

2.39 User Pay Customer:

Means a Residential Service Customer occupying, as a tenant, a dwelling owned or leased by the Northwest Territories Housing Corporation.

2.40 Wholesale:

Means a Customer that is a business whose primary purpose is to distribute and re-sell electricity purchased from the Corporation.

3.0 **Agreement**

3.1 Application:

These Terms apply to the Corporation and to every Applicant and Customer.

3.2 Contract:

Notwithstanding the provisions of Section 3.1, and subject to approval by the Board, the Corporation may enter into a contract with a Customer specifying the terms and conditions of Service, which may vary from and supersede these Terms.

3.3 Resale:

Without the prior written consent of the Corporation, a Customer may not sell, exchange or otherwise dispose of Energy provided by the Corporation.

3.4 Ownership:

The Corporation retains ownership of all facilities used to provide Service to a Customer, whether or not facilities are located on lands owned by the Corporation, and whether or not the capital cost of such facilities were in whole or in part paid by the Customer.

Unless a contract between the Corporation and the Customer specifically provides otherwise, payment made by a Customer for costs incurred by the Corporation in

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installing facilities does not entitle the Customer to ownership of any such facilities.

3.5 Customer Generation:

A Customer must sign an agreement with the Corporation if the Customer wishes to use Service:

- a) in parallel operation with; or
- b) as supplementary, auxiliary or stand-by Service to any other source of Energy.

The Corporation will provide retail stand-by service to back-up customer self-generation where surplus capacity is available. Rates for such service shall be established by the Board.

3.6 Frequency and Voltage Levels:

The Corporation will make all reasonable efforts to supply Electricity at 60-Hertz alternating current. The voltage levels and variations will comply with those specified as "standard" by the Canadian Standards Association. Not all standard voltages may be available at a particular location.

4.0 **Application for Service**

4.1 General:

To enable the Corporation to provide the requested Service, an Applicant may be required by the Corporation to supply information either verbally or in writing respecting their Connected Load, preferred supply conditions, lot number or street address, location of building on lot, and any other pertinent information requested by the Corporation, such as credit history or references. An Applicant shall be required to sign a Customer Service Order (CSO) or enter into a written contract for Service.

For a new electric Service location, the Customer must ensure that the Corporation has received each applicable permit and connection authorization directly from the applicable Electrical Safety Division of the Government of the Northwest Territories.

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Before connecting any Service, the Corporation will inform the Applicant if there are any special conditions that must be satisfied and the satisfaction of any such conditions shall be a precondition to the Corporation commencing Service.

~~The Corporation may refuse to provide Service to an Applicant if a former Customer currently resides at the Applicant's premises has existing arrears to the Corporation and the Corporation in its sole discretion acting reasonably believes, that the Customer in arrears would continue to reside at the Applicant's premises.~~

Notwithstanding anything in section 4.1, whether or not a Customer has signed a Customer Service Order or contract for Service, these Terms and Conditions and the rates applicable to the Service supplied by the Corporation will apply to any Customer receiving Service from the Corporation.

4.2 TMI Deposit:

Where an Applicant or Customer are required by these Terms and Conditions to pay a TMI Deposit, the TMI Deposit will be determined in accordance with the Miscellaneous Fees/Charges set out in Schedule C.

4.3 Service Connection:

Where the Corporation does not have linemen based in a community, a Service connection in the Community will be completed during the Corporation's next scheduled maintenance work in the community following the date that the Corporation agrees to provide the Service connection.

If the Customer requests that Service commence earlier than the Corporation's next scheduled maintenance work in the Community, the Customer will be required to sign a TMI for the cost, as estimated by the Corporation, of connecting the Service at an earlier date, and must provide a TMI Deposit prior to the date any work respecting the Service connection is commenced by the Corporation. After the work is completed, the Corporation will make any adjustments necessary to the TMI to reflect the Corporation's actual cost of performing the work. The Customer will pay

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any additional amounts owing under the TMI, or the Corporation will refund any excess amounts paid by the Customer, as applicable. The Corporation will not commence providing Service until all amounts owing to the Corporation under the TMI are paid in full.

4.4 Short-Term Temporary Service:

Where an Applicant requests Short-Term Temporary Service, or the Corporation in its sole discretion acting reasonably, believes that Service requested by an Applicant will be Short-Term Temporary Service, the Applicant shall, prior to the Corporation commencing any work on the Service connection, pay the Corporation's total cost as estimated by the Corporation of installation and removal of the required Corporation Facilities, plus the cost of unsalvageable material as follows:

- a) At the time the Applicant submits request for Service, the Applicant must sign a TMI and provide a TMI deposit.
- b) Following the termination of Service the Customer shall be reimbursed or invoiced for the difference between the TMI deposit paid and the aggregate of the actual cost of construction, plus the cost of unsalvageable material, plus the removal costs as estimated by the Corporation.
- c) Following the removal of the Corporation Facilities required to provide Service to the Customer, the Customer will be reimbursed or invoiced for the difference between the estimated costs and the actual Corporation Facilities removal costs.

4.5 Rejection of Application for Service:

The Corporation may, in its sole discretion acting reasonably, reject any Applicant for Service when:

- a) the type or quantity of Service requested is not available or normally provided by the Corporation in the locality where Service is requested;
- b) the Applicant or Customer does not have currently in force all permits or other authorization that may be required for the connection;

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- c) the Corporation determines at its sole discretion acting reasonably that the Applicant is not credit-worthy, or a previous or other account held by the Applicant with the Corporation is in arrears;
- d) the Applicant fails to provide a security deposit or letter of credit from a suitable institution in a form and substance acceptable to the Corporation;
- e) the Corporation requires a separate contract due to the unique nature of service conditions;
- f) any representation made by any Applicant to the Corporation for the purpose of obtaining Service is, in the Corporation's opinion acting reasonably, fraudulent or misleading; or
- g). the Applicant has not, after being requested by the Corporation to do so, provided a signed written Customer Service Order or contract for service, or has refused to sign these documents in person.

5.0 Charges for Service

5.1 Connection Fee:

Whenever a Service connection is made, the Customer shall pay a non-refundable connection fee as set out in Schedule C.

If the Corporation agrees to make a connection other than during the Corporation's normal schedule for such work, the Corporation may charge by way of a TMI in addition to the amount set out in Schedule C its cost to make the connection, but in no event may the Corporation charge in excess of the Corporation's actual cost to make the connection.

The connection fee will be included in the Customer's first billing.

5.2 Reconnection:

When the Corporation receives an Application for the relocation of Service or is requested to reconnect or restore Service to a Customer whose Service was previously discontinued by the Customer, terminated by the Corporation or restricted by a current-limiting device, the Customer shall pay:

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- a) all amounts owing to the Corporation, which shall include, if reconnection occurs within 12 months and billed at rates where Demand Charges apply, the Demand Charge in effect immediately prior to disconnection for each month of the interval between disconnection and reconnection;
- b) a reconnection charge as per Schedule C attached hereto if the reconnection is made during the Corporation's normal schedule for such work, or in any other case, an amount not exceeding the Corporation's actual cost of reconnection; and
- c) the security deposit required under Sections 5.7 and 5.8.

Where a metered service has been disconnected for a continuous period of 90 days or more, the Corporation in its sole discretion acting reasonably may require an electrical inspection of the Customer Facilities at the Customer's sole expense.

5.3 Application of Rate Schedules:

The Customer shall pay the charges for Service as set forth and contained in the applicable Rate Schedules in effect from time to time.

Where a Customer is receiving service for both Residential and General Services, the General Service rate applicable in the Service area will be charged in respect of all Energy provided to the Customer at the Customer's Point of Delivery. Provided, however, that if the customer installs, to the Corporation's satisfaction, separate meters to record the amount of Energy used for each of Residential and General Services, then the Corporation's applicable General Service rate will apply to the energy consumed under General Service and the Corporation's applicable Residential Service Rate will apply to the Energy consumed under Residential Service.

Residential Service rates applicable in the Service area will apply to Temporary Construction Service where a Customer is building his/her own single family residence.

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General Service rates applicable in the Service area will be applied to Temporary Construction Service provided to a contractor/developer for the building of homes other than the contractor's/developer's private residence.

General Service rates applicable in the Service area will be applied to Temporary Construction Service respecting non-residential construction projects.

5.4 Power Amplifier Boxes:

Service provided for power amplifier boxes shall be billed at the General Service rate applicable in the service area assuming continuous use of the power amplifier box at its maximum rated consumption. At the Customer's request, and after the Customer has installed a CSA approved meter receptacle, the Corporation will install a meter. Power Amplifier Boxes affixed to Corporation's Facilities are a Joint Use Service and shall be charged for in accordance with Section 8.0. Service provided in respect of the power amplifier box will be billed based on actual consumption recorded by the meter.

5.5 Power Bill Copying Charge:

The Customer will be subject to a fee for being provided an additional copy of a power bill, including any related documentation, The charge for providing this service is set out in Schedule C.

5.6 Change in Service Requirements:

Where the purpose for which a Customer uses all or a portion of the Service provided by the Corporation changes from one classification to another, the Customer will immediately notify the Corporation of the change. When the Corporation is so notified, or when the Corporation believes on reasonable grounds that the purpose has changed, the Corporation will calculate the Customers bill on the basis of the rate which the Corporation, acting reasonably in the circumstances, determines to be applicable to the Service commencing in the next billing period.

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5.7 Security Deposit:

The Corporation shall require a security deposit as a pre-condition to Service or an increase to an existing security deposit where:

- a) credit worthiness has not been established by an Applicant for Service to the satisfaction of the Corporation;
- b) accounts are in arrears for previous Service to the Applicant by the Corporation;
- c) Service is to be reconnected which has been discontinued for reasons of non-payment of accounts;
- d) the Service to be provided will be Short-Term Temporary Service; or
- e) the Customer is the subject of bankruptcy, insolvency or a similar proceeding, enters into receivership, or ceases to be a corporate entity.

5.8 Amount of Security Deposit:

A security deposit, when payable, shall be in a form and substance acceptable to the Corporation in the following amounts:

a) Residential Service:

For Customers with less than one year of previous billing history with the Corporation, an amount as set out in Schedule C.

As an alternative to a security deposit, the Corporation may, at its sole discretion acting reasonably, accept from an Applicant for Residential Service proof of a good credit history from a utility service within the last 12 months or a letter attesting to the Customer's good credit history from a chartered bank.

c) User Pay Customer:

For User Pay Customers, an amount set out in Schedule C.

c) General, Short-Term Temporary, Industrial and Wholesale Customers Service:

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For a Customer at a location or Point of Delivery with less than one year of previous billing history with the Corporation, an amount, as estimated by the Corporation, equal to the sum of the billings for the two months during which the Corporation forecasts the highest consumption of Energy at the Customer's Service location during the next 12 month period.

For a Customer at a location with at least one year of previous billing history with the Corporation, an amount, as calculated by the Corporation, equal to the sum of the billings for the two months having the highest Energy consumption during the most recent 12 month period.

As an alternative to a security deposit, the Corporation, at its sole discretion acting reasonably, may accept from an Applicant an irrevocable letter of credit from a Canadian chartered bank.

The Corporation has the right to immediately issue a 48 hour notice of disconnection to a Customer if the Customer's cheque for a security deposit is not honored by the Customer's financial institution.

5.9 Interest and Refund of Deposits:

The Corporation will pay simple interest on the security deposit from the date the deposit is paid, at an annual rate of interest equal to the daily interest savings rate in effect at the end of each month as posted by the Bank of Nova Scotia. Such interest will be credited monthly to the Customer's security deposit account for each full month that the security deposit is held by the Corporation.

A Customer's security deposit will be refunded after 1 year of good credit history with the Corporation, or when the Customer is disconnected from Service other than for default in payment of accounts. Security deposits will be returned to the Customer by way of credit to the Customer's account.

5.10 Use of Security Deposits

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If a Customer fails to pay an amount billed, and collection action has been initiated by the Corporation, the Corporation may apply all or any portion of a Customer's security deposit toward payment of the amount(s) in arrears, including interest.

When the Corporation has taken this step, the Customer may be required to pay a security deposit as required under Sections 5.7 and 5.8, or to pay to the Corporation the amount deducted from the Customer's security deposit.

Upon termination of Service, the Corporation may apply all or any portion of a Customer's Security Deposit, including interest, toward payment of any amount due and owing by that Customer.

6.0 Municipal Street Lighting Service

6.1 Street Lighting Service Conditions:

The Corporation shall be responsible for the provision of Energy to the street light luminaires. The Corporation shall also be responsible for normal maintenance of the luminaires, photo electric cell replacement and lens cleaning and replacement.

The Corporation shall not be responsible for excessive damage due to vandalism.
(see Section 6.3 below)

6.2 Maintenance Adjustment:

Upon being notified in writing of an outage of a luminaire:

- a) Where the Corporation has linemen based in the community in which the outage occurred, the Corporation will use reasonable efforts to carry out maintenance to restore Service within one week of having received such notice. Should the Corporation be unable to carry out the maintenance required to restore the luminaire within one week of having received written notice, a credit towards the monthly rental applicable to the luminaire shall be given by the Corporation to the Customer based on the length of the outage.

- b) Where the Corporation does not have linemen based in the community maintenance will be carried out during the next regularly scheduled

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maintenance trip to the community following the Corporation's receipt of such notice. If the Corporation has been unable to carry out the maintenance required to restore the luminair within three (3) months after being notified of the outage, a credit towards the monthly rental applicable to the luminair shall be given by the Corporation to the Customer based upon the length of the outage.

- c) If a Customer requests that the Corporation carry out maintenance work prior to the Corporation's next regularly scheduled maintenance trip, the Customer will be billed for the Corporation's costs of performing such maintenance by way of a TMI, and a TMI deposit must be paid by the Customer before maintenance work will commence. After the maintenance work is complete, the Customer will be invoiced or refunded the difference between the Corporation's actual cost to complete the maintenance work and the TMI deposit.

6.3 Vandalism:

The Corporation will absorb the maintenance costs associated with the repair of vandalized luminaires to a maximum annually in each community of one luminair or 1% of the total number of luminaires in the community, whichever is greater.

Repetitive breakage or extreme breakage at one time shall not be absorbed by the Corporation. Vandalism of this type shall be reported to the Local Authority, outlining the extent of the damage and the estimated cost of repair. Providing the Local Authority agrees in writing to absorb these costs, the Corporation shall effect repairs and restore Service. Otherwise, the street light luminair(s) shall be removed and billing shall be immediately discontinued.

6.4 Application for Street Lighting Service:

Municipal Corporations requesting municipal Street Lighting Service shall do so in writing to the appropriate Corporation office. The request shall specify the number, type and size (Watts) of luminaires required, and be accompanied by a suitable plan

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indicating the location where each luminair is to be installed. The Corporation shall not bear any responsibility in regard to the adequacy of lighting resulting from the number, type and size of luminaires requested.

The Corporation shall review the Municipal Corporation's request and advise the Municipal Corporation in writing of present charges for the Street Lighting Service requested and if any additional charges shall be applied due to unusual installation circumstances (see Section 6.6).

6.5 Installation:

Upon receiving written approval from the appropriate authority to proceed, the Corporation shall purchase, install and energize the street light luminaires at a time during the normal course of its maintenance schedules. Billing shall commence immediately after the installation is completed.

6.6 Non-Standard Service:

Charges for Street Lighting Service are based upon the installation of luminaires on existing wood poles provided for distribution of overhead Service in the community. Should additional wood poles, transformers, secondaries or other facilities be required, the cost of providing and installing the additional facilities is the responsibility of the Customer.

Should non-wood poles and/or underground wiring be required, this may be done by the Corporation at the cost of the Customer.

7.0 **Private Area Lighting Service**

7.1 Application for Service:

Customers requesting Private Area Lighting Service shall do so in writing to an appropriate office of the Corporation. The request shall specify the number, type and size (Watts) of luminaires required and be accompanied by a suitable plan indicating the location where each luminair is to be installed and identifying the Customer's power source for each fixture. The Customer is responsible for ensuring

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that the Corporation has received all applicable permits and connection authorization directly from the applicable Electrical/Mechanical Safety Division of the Government of the Northwest Territories.

7.2 Installation:

The Corporation shall review the Customer's request and advise in writing, in a timely manner, the estimated cost of providing this installation.

Upon receiving payment for the estimated cost of the installation, in advance, from the Customer, the Corporation shall purchase, install and energize the area lighting.

Any difference between the estimated cost and the actual cost incurred by the Corporation shall be either invoiced or refunded to the Customer.

Power supply for Private Area Lighting Service may be from the Customer's metered distribution panel, or at the option of the Corporation, from a separate power supply.

7.3 Rates Classification:

Where separate metering is in place for Private Area Lighting Service, the rate classification shall be that associated with the classification of Service being provided to the Customer.

Where the Private Area Lighting Service is not metered, the Corporation will charge monthly fixed rates as determined in accordance with its Rates Schedules.

7.4 Ownership:

The Corporation shall not purchase, lease, or otherwise become the owner of Private Area Lighting Facilities. Subject to Section 7.5 the Customer shall be responsible for all maintenance of the Facilities.

7.5 Maintenance:

The Corporation may enter into a maintenance agreement for facilities for Private

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Area Lighting Service provided that the Customer signs a TMI and provides a TMI Deposit as set out in Schedule C prior to maintenance work commencing. Any difference between the TMI Deposit paid and the actual cost incurred by the Corporation shall be either invoiced or refunded to the Customer.

8.0 Joint Use Service

Joint Use Service shall, by separate agreement, be made available to electrical or communication utilities in areas in which the Corporation provides Service, for leasing of space on existing Corporation transmission and distribution poles, where sufficient space is available, and in accordance with specific terms and conditions outlined in a contract with each Joint Use Service Customer.

9.0 Service Conditions

9.1 Point of Delivery:

Any Point of Delivery for Service shall be at a location approved by the Corporation.

When metering is appropriate, Service shall be provided to the Customer through a single meter and each individual unit within a multiple dwelling building will be served as a separate Point of Delivery, unless the Corporation agrees otherwise.

Where the Corporation and a Customer have agreed that Service to a Multiple Unit Dwelling shall be delivered through a single Point of Delivery, the applicable General Service rates will apply to the Service.

All meters and associated equipment connected to the Point of Delivery shall be owned and maintained by the Corporation.

9.2 Mobile Homes and Multiple Unit Dwellings:

Service shall normally be provided to mobile homes and units of a Multiple Unit Dwelling through separate Points of Delivery, based on the applicable Residential Service rates.

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Where a common Point of Delivery exists for a number of mobile homes or units of Multiple Unit Dwelling, billing shall be at the applicable General Service rates.

Service provided to common use areas (e.g., laundry facilities) for a number of mobile homes or units of Multiple Unit Dwelling shall be separately metered and billed at the applicable General Service rates.

9.3 Customer Facilities:

The Customer shall, at his own cost, provide and maintain, in good repair and condition, in a location, approved by the Corporation, suitable accommodation for the Corporation Facilities required for the supply of Service at the Point of Delivery. All Customer Facilities from the Point of Delivery into the Customer's premises shall be provided and maintained by the Customer in accordance with applicable statutes, regulations, standards and codes and any directions given by the Corporation. The Customer shall be responsible for providing suitable devices to protect the Customer's service entrance and equipment connected thereto from overload, single phasing and abnormal voltage or supply conditions.

The Corporation is entitled to limit the size and nature of equipment installed by a Customer at a service location in order to control voltage fluctuations if, in the Corporation's opinion, acting reasonably the equipment could adversely affect the Corporation's Facilities or operations.

9.4 Interference

The Customer shall not interfere with any Corporation Facilities.

The Customer shall permit the Corporation to manage vegetation on the property owned or controlled by the Customer to maintain proper clearances and reduce the risk of contact with the Corporation's Facilities.

9.5 Delay in Taking Service:

If, with respect to an application to extend Corporation Facilities to any Point of

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Delivery, the Corporation has reason to believe that the provision of Service to that Point of Delivery will not be taken within 30 days after Service is available, then the Customer shall pay, as a precondition of Service to such Point of Delivery, the amount of the Maximum Corporation Investment as determined in accordance with Schedule "A" for the type of Service provided.

Upon commencement of Service and payment by the Customer for Service, the additional amount paid by the Customer on account of the Maximum Corporation Investment shall be refunded.

9.6 Customer Extensions:

A Customer shall not extend Customer Facilities beyond property owned or occupied by the Customer.

9.7 Extension of Service:

Subject to Section 9.6 of these Terms and Conditions, if the Corporation's estimated cost of extending Customer Facilities at the request of a Customer is less than the Maximum Corporation Investment specified in Schedule "A" for the type of

Service provided, the Customer will not be required to make any construction contribution.

In all other cases, an agreement providing for payment of the extension charges in excess of the Maximum Corporation Investment in respect of such extension, calculated in accordance with Schedule "A", shall be a precondition to the Corporation's commencement of work on such extension.

If the Corporation determines that it is necessary to install Corporation Facilities to provide a requested Service that are different from the Facilities that the Corporation typically installs to provide Service, the Customer will pay the costs for such materials and equipment.

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9.8 Underground Service Extensions:

The extension of underground distribution facilities shall be undertaken subject to the conditions set out in Schedule "B" and shall be subject to the Maximum Corporation Investment and required Customer Construction Contribution as determined in accordance with Schedule "A".

9.9 Conversion from Overhead to Underground Service:

When a Customer requests that existing Corporation Facilities be converted from overhead to underground, the Customer shall pay, in advance, the estimated cost to be incurred by the Corporation in connection with the conversion, including but not limited to the following:

- a) the original capital cost of the existing Corporation Facilities being removed, less accumulated depreciation; plus
- b) the estimated cost of removing the existing Corporation Facilities, less the estimated salvage value; plus
- c) the estimated cost for the installation of the new underground Corporation Facilities, less any applicable increase in the Maximum Corporation Investment calculated in accordance with Schedule "A".

Any difference between actual and estimated costs shall be invoiced or refunded to the Customer without interest.

9.10 Relocation of Facilities:

If the Customer wishes to relocate any Corporation Facilities, the Customer shall provide an alternate location and valid permit satisfactory to the Corporation and shall pay to the Corporation, in advance, the estimated costs of the relocation. Upon completion of the relocation, any difference between the actual and the estimated costs shall be invoiced or refunded to the Customer.

10.0 **Rights of Way and Access to Facilities**

10.1 Easements:

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The Customer shall grant, or cause to be granted, to the Corporation, without cost to the Corporation, such easements or rights-of-way over, upon or under the property owned or controlled by the Customer as the Corporation reasonably requires to provide Service to such Customer.

10.2 Right of Entry:

The Corporation's employees or agents shall have the right to enter a Customer's property with the exception of residential areas at all reasonable times for the purpose of installing, maintaining, monitoring and removing the Corporation's Facilities and for any other purpose incidental to the provision of Service.

The Corporation shall have the right to enter a Customer's property at any time for the purpose of dealing with any emergency situation relating to or posing a threat to persons, property, Corporation Facilities, and/or the provision of Service.

After termination of the Service to any Customer, the Corporation shall have the right, at reasonable times, to enter onto the Customer's land and premises to remove the Corporation's Facilities.

The Customer shall provide the Corporation with reasonable access to Corporation Facilities located on the Customer's property.

10.3 Access to Meters:

The Customer shall provide and maintain reasonable access to the Corporation to all metering equipment for the purpose of changing, servicing and reading such equipment. Where the Customer's Service address or location is generally locked during normal business hours, the Customer shall provide the Corporation with a key to permit access to the meter.

If the Corporation informs a Customer that reasonable access to metering equipment is not being provided, then the Customer must take immediate action to remedy the situation. If the Customer fails to remedy the situation within a

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reasonable time the Corporation, at its sole discretion may estimate consumption until the situation has been remedied in which case the Customer shall be billed on the basis of the Corporation's estimates; or

- a) remedy the situation on behalf of the Customer and apply the costs to the Customer's next regular billing; or
- b) both a) and b); or
- c) discontinue Service in accordance with Section 16 of these Terms and Conditions of Service.

11.0 Metering

11.1 Installation:

The Corporation shall provide, install and seal all meters necessary for any measurement in connection with the Service supplied to a Customer, unless otherwise specifically provided in a contract with the Customer.

Any metering equipment used by the Corporation shall be installed, connected, operated and tested in accordance with the applicable statutes, regulations, standards, and codes

Each Customer shall provide and install a Measurements Canada approved meter receptacle or other facilities suitable for the installation of the Corporation's meter or metering equipment.

The Corporation may replace meters from time to time at its discretion.

11.2 Location:

The Corporation and the Customer will determine a reasonable location for a meter, and the Customer will make the location available for the installation of the meter.

In selecting a meter location, the parties will, among other things, have regard for applicable statutes, regulations, standards and codes, the type of Service required

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and convenience of access to the meter. The Customer will ensure that the meter is reasonably accessible to The Corporation.

Meter receptacles shall be installed on the exterior of single family detached and Multiple Unit Dwellings, row housing and other similar dwellings. Where more than one meter is to be installed, the meters shall be grouped in a suitable location on the exterior of the building.

Meter receptacles shall also be installed on the exterior of buildings that are closed during normal working hours such as churches, arenas, sewage stations, summer cottages, seasonal commercial buildings, etc.

Meter receptacles shall not be installed in locations that are not readily accessible or likely to become inaccessible by the construction of fences, garages, or other types of structures.

Meter receptacles installed on the exterior of buildings shall be located and maintained at a point not less than 1.6 metres or more than 1.8 metres above finished grade (measurement taken to meter face).

Meter receptacles installed in pedestals for trailer courts or parks shall be located at a point not less than 1.6 metres or more than 1.8 metres above finished grade (measurement taken to meter face). In the case of single meter pedestals, the meter receptacle shall be installed such that it faces the road.

Meter receptacles may be installed indoors for Customers receiving General Service unless they are components of approved metering modules and shall be installed at a height not less than 1.2 metres or more that 1.8 metres above the finished floor (measurement taken to meter face).

Meter receptacles installed on switchboards in multiple unit dwellings may be installed at a minimum height of 45 cm above the finished floor provided that the

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room in which the switchboard is located is used solely as a mechanical or electrical room. Where a meter is installed on a Customer-owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electrical Code and any other applicable legislation.

If the Corporation informs a Customer that meter receptacles have not been installed and maintained within these guidelines, then the Customer must take immediate action to remedy the situation. The Corporation may discontinue Service to a Customer if the Customer fails to remedy the situation within the time provided for in the notice to the Customer, or the Corporation may, following notice to the Customer, move the meter to a location acceptable to the Corporation and include the costs associated with moving the meter to the Customer's next regular bill.

11.3 Meter Tests and Adjustments:

A meter may be inspected by the Corporation at any reasonable time, and shall be inspected and tested upon the written request of a Customer, provided the request is accompanied by a Meter Accuracy Test Deposit as set out in Schedule C. Meters shall be tested or calibrated by an official designated by the Department of Measurement Canada and Corporate Affairs (Canada) or such other government department as may from time to time be charged with that responsibility.

In the event that the test of the meter discloses that it is not accurate within the limits prescribed by the *Electricity and Gas Inspection Act* S.C. 1980-81-82-83, the Meter Accuracy Test Deposit paid by the Customer shall be refunded to the Customer and the billings to the Customer based upon readings of the inaccurate meter shall be adjusted to correct for the error. Unless an examination of past meter readings or other information discloses the time at which the error commenced, then the error shall be deemed to have commenced on the date which is three months prior to the date of the testing of the meter or the date upon which the meter was installed or last tested, whichever occurred later.

In the event that the test of the meter discloses that it is accurate within the limits

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prescribed by the *Electricity and Gas Inspection Act* S.C. 1980-81-82-83, and regulations, standards or guidelines thereunder, The Corporation shall charge the Customer the Meter Accuracy Test Fee set out in Schedule C equal to the Corporation's actual cost of having the meter tested less the Meter Accuracy Test Deposit paid by the Customer.

11.4 Energy or Demand Diversion:

If under any circumstance a person prevents a meter from accurately recording the total Demand or Energy supplied, the Corporation may disconnect the Service without notice and take other appropriate actions.

The Corporation may then estimate the Demand and amount of Energy supplied but not registered at the Point of Delivery. The Customer shall pay the Corporation for the cost of the estimated Demand and Energy consumption plus all costs related to the investigation and resolution of the Service diversion.

12.0 **Meter Reading and Billing**

12.1 Meter Readings and Estimates:

In the case of metered Services, the invoices for Service provided to the Customer shall be based upon actual meter readings. In circumstances where the Corporation is not able to obtain meter readings for any reason including, without limitation, locked doors, weather conditions, vandalized equipment, or equipment failure, invoices for Service shall be based upon meter readings estimated by the Corporation. These estimates will be adjusted if and when actual meter readings are obtained.

Should the meter reading be disputed, the Customer shall pay the amount described as owing in the invoice. Upon certification of the meter reading, the Corporation will make all necessary adjustments.

12.2 Billing Adjustment

Notwithstanding that bills are required to be paid in full, the following billing

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adjustments shall apply.

a) Over-billing:

The Corporation will refund to the Customer any amount which the Corporation incorrectly collected for the entire duration of the over-billing on the Customer's next bill following the discovery of the over-billing. If the duration of the over-billing cannot be determined with reasonable accuracy, the amount refunded will be the amount of the over-billing for the 3 months prior to the discovery of the over-billing.

b) Under-billing:

The Corporation will invoice the Customer for any amount which the Corporation incorrectly did not collect from the Customer for the entire duration of the under-billing, up to a maximum period of 12 months. If the duration of the under-billing cannot be determined with reasonable accuracy, the amount invoiced will be the amount of the under-billing for the 3 months prior to discovery of the under-billing.

Notwithstanding the above; the adjustment period for under-billing will be for the entire period, regardless of the length of time, if the Customer has tampered with the meter or the Corporation Facilities, or has otherwise used Service provided by the Corporation in an unauthorized way.

If an instance of under-billing to a Customer's account is due to negligence or willful misconduct on the part of the Corporation, no adjustments will be made to the Customer's account for that instance of under-billing.

In all cases of adjustments to under-billed accounts, The Corporation shall determine reasonable terms of repayment. The repayment shall be interest free and in equal installments corresponding to the Corporations normal billing cycle. Section 12.6 of these Terms dealing with late payment charges will apply if the repayment schedule is not adhered to.

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Adjustments for over-billing or under-billing will not be made to closed accounts with positive or negative balances of \$5.00 or less.

12.3 Payment of Accounts:

Accounts in respect of charges for Service shall be sent on a monthly basis to Customers by the Corporation and the accounts become payable in full:

- a) where the accounts are delivered by hand to the Customer the day they are so delivered;
- b) where the accounts are sent by mail to the Customer, 21 days following the billing date on the invoice; or
- c) where the accounts are faxed or delivered by electronic mail, 24 hours after they are sent.

Failure to receive a bill does not relieve a Customer from the obligation to pay the amount owing for any Service provided by the Corporation. Late charges shall apply pursuant to Section 12.6 of these Terms.

Should any billing by the Corporation be disputed, the Customer shall pay the full amount described as owing in the invoice. Upon certification of the billed amounts, the Corporation will make all necessary adjustments.

In addition to payments for Service, the Customer is required to pay to the Corporation the amount of any tax or assessment levied by any tax authority on Service provided to the Customer (e.g., Goods and Services Tax).

Partial payments on an account will be applied to the unpaid amounts outstanding on the oldest bills first. Partial payment by a Customer in no way eliminates the Customer's requirement to pay the total unpaid amount outstanding on a power bill.

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12.4 Collections Administration Fee:

The Corporation shall commence collection action when accounts are past due. When collection action is initiated, the Administration Fee for Commencing Collection Action set out in Schedule C may be assessed for initiating the collection action to the Customer's account to partially recover the administrative cost of said action.

12.5 Proration of Initial and Final Billings

An amount payable to the Corporation for a Customer Service Charge, Demand Charge or Facilities Charge will not be pro-rated. These charges shall be applied in full for any initial or final billings. The Corporation may, at its sole discretion, choose to waive these charges for billings of less than seven days where there has been no consumption of electricity by the Customer.

Final Billing charges totalling less than \$5.00 will not be billed to a Customer.

12.6 Late Payment Charge

The Corporation shall, in addition to other charges, impose a late payment charge computed at a rate of one and one-half (1 1/2) per cent per month (19.562% per year) on the balance in arrears, for accounts which are not paid within 7 days after the account becomes payable.

12.7 Dishonoured Payments:

An additional administrative charge equivalent to that charged by Chartered Banks may be assessed to reflect the administrative cost of processing any dishonoured payment. Dishonoured payments include cheques returned by the Customer's bank for any reason such as non-sufficient funds (NSF), stale dated, body and figures differ, unsigned, closed account, cheque cannot be traced, etc.

Following the receipt of three (3) dishonoured payments from a Customer, the Corporation shall notify the Customer that only cash, a money order or certified cheque will be accepted for payment.

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12.8 Outstanding Charges:

The Corporation may add to a Customer's bill charges authorized by these Terms and owing to the Corporation by the Customer, including Construction Contribution, TMI and any charge set out in Schedule C.

13.0 **Corporation Responsibility and Liability**

13.1 Continuous Supply:

The Corporation shall make all reasonable efforts to maintain uninterrupted Service to its Customers, but the Corporation cannot guarantee uninterrupted Service.

Where a plant or any part of a plant malfunctions and the Corporation is unable to supply Service, the Corporation shall, with due regard for cost and circumstance:

- a) promptly make repairs; and
- b) pending repairs, take all reasonable steps to supply Service from other sources if other sources are reasonably available.

The Corporation shall, whenever possible, give the Customer reasonable notice of any anticipated interruption of Service and will endeavour to ensure that such interruptions are as short and infrequent as circumstances permit.

13.2 Limitation of Corporation Liability:

~~Notwithstanding anything to the contrary contained in these Terms, the The Corporation shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind (including legal and other professional fees and disbursements), whether of direct, indirect, special, exemplary, punitive or consequential nature (excepting only direct or indirect, which the Customer may suffer, sustain, pay or incur (collectively, "Losses") arising out of or in any way connected with (i) any use of Service by the Customer, or (ii) any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Corporation to the Customer, other than Losses for direct physical loss, injury or damage to a Customer or a~~

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Customer's property to the extent resulting directly from the negligent acts or omissions or willful misconduct of the Corporation, its employees or agents) ~~arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Corporation to the Customer. For the purpose of the foregoing and without otherwise restricting its generality, "direct physical loss, injury or damage"~~ shall not include.

Notwithstanding any other provision contained in these Terms, the Corporation shall not be liable for any indirect, special, exemplary, punitive or consequential nature, including without limitation loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, loss of opportunity, cost of purchased or replacement capacity or Energy, cost of capital, business interruption, loss of use of any facilities or property, claims of a Customer's customers, contractors or other third parties, or any other similar damage, expense, cost, liability or loss whatsoever ~~arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of Service to a Customer, whether or not any such loss, damage, expense, cost or liability was foreseeable.~~

14.0 Customer Responsibility and Liability

14.1 Indemnity:

The Customer shall indemnify and save harmless the Corporation from and against ~~all costs, liabilities, losses, claims, expenses (including legal and other professional fees and disbursements) and damages of whatsoever nature or kind which the Corporation may incur and from all claims of third parties for any costs, damages, expenses, losses, injuries or loss of life~~ Losses arising out of or in any way connected with ~~the~~ (i) any defect, fluctuation, reduction or interruption in the provision of Service by the Corporation to the Customer, other than Losses for direct physical loss, injury or damage to a Customer or a Customer's property to the extent resulting directly from the negligent acts or omissions or ~~wilful~~ willful misconduct of the Corporation, its employees, ~~contractors, or agents~~ or agents.

Notwithstanding any other provision contained in these Terms, the Corporation shall

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not be liable for any indirect, special, exemplary, punitive or consequential nature, including without limitation loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, loss of opportunity, cost of purchased or replacement capacity or Energy, cost of capital, business interruption, loss of use of any facilities or property, claims of a Customer's customers, contractors or other third parties, or any other similar damage, expense, cost, liability or loss whatsoever.

14.2 Required Permits, Licenses and Authorizations:

The Customer shall ensure that all required permits, licences, and authorization are provided to the Corporation prior to:

- a) commencement of Service;
- b) any change of service requirements at any point of delivery; or
- c) commencement of construction of new service extensions.

14.3 Customer's Facilities:

The Customer shall be responsible for the installation and condition of all Customer's Facilities on the Customer's side of the Point of Delivery, except metering or other equipment owned by the Corporation.

14.4 Customer's Installation and Operation:

Any Customer Facilities supplied with Service shall be installed in accordance with the applicable statutes, regulations, standards and codes and only after the Corporation has given its consent and any necessary inspections have been successfully completed such equipment will be operated so as to cause no interference with the Corporation Facilities or with any other Customer's Service. The Customer will be responsible for costs associated with installing, maintaining, repairing and replacing the Customer Facilities.

14.5 Improper Operation or Installation:

Should the Customer fail to comply with Section 14.3, the Corporation may immediately suspend the supply of Service. Service will be recommenced when this

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failure is remedied to the satisfaction of the Corporation.

14.6 Customer's Protection:

The Customer shall be responsible for determining whether any devices are needed to protect the Customer's equipment from damage that may result from the provision of Service by the Corporation. The Customer shall provide and install any such devices.

14.7 Notice of Service Change:

The Customer shall provide the Corporation with reasonable prior notice of any significant change in the Customer's Connected Load to the Service which is supplied. Notwithstanding any other provision of these Terms, the Corporation shall not be obligated to supply any Demand in excess of that agreed to by the Corporation.

14.8 Damage:

The Customer shall be responsible for all damage caused to Corporation Facilities located on the Customer's premises where the damage is caused by the negligent acts or omissions or wilful misconduct of the Customer or anyone permitted by the Customer to be on the premises. At the Corporation's sole discretion, the costs associated with such damages will either be added to the Customer's regular bill or will be billed on a separate invoice issued to the Customer.

14.9 Changes to Corporation Facilities:

If the Corporation must modify its Corporation Facilities to accommodate a Customer load or Service change, the Customer shall pay for all costs in connection with such modification including the following costs:

- a) the original capital cost of the existing Corporation Facilities being removed, less accumulated depreciation and any amount paid by the Customer as a customer contribution toward those Corporation Facilities; plus
- b) the Corporation's estimate of the cost of removing the existing Facilities, less

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- the estimated salvage value of those Corporation Facilities; plus
- c) the Corporation's estimate of any other costs that may be associated with the removal of the existing Corporation Facilities.

Any difference between the actual costs incurred and the estimated costs shall be refunded or invoiced to the Customer.

14.10 Service Calls:

If the source of a Customer-requested service call is the Customer Facilities, the Customer may be required to sign a TMI and to provide a TMI Deposit prior to any work being undertaken by the Corporation.

Following satisfactory completion of the service call, the Customer will be invoiced or refunded the difference between the TMI Deposit paid and the actual costs incurred by the Corporation.

If the Corporation responds to a request by the Customer for Service of Customer Facilities, then the Corporation may charge the Customer a service call response fee as set out in Schedule C, whether or not the Corporation installs, maintains, repairs, or replaces any Customer Facilities.

15.0 **Termination of Service by Customer**

15.1 Notice:

Except where otherwise provided in a contract between the Corporation and a Customer, a Customer may, at any time, give the Corporation reasonable written notice, in advance, that the Customer wishes Service to the Point of Delivery terminated. Upon receipt of such notice, the Corporation shall read the Customer's meter within a reasonable time, and shall use its best efforts to read the Customer's meter at the time requested by the Customer. A Customer shall be liable for all amounts owing in respect of Service provided to the time of such reading.

Where the Customer's account is connected to a third party property and/or asset

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(e.g., User Pay Customers and the Northwest Territories Housing Corporation), the Corporation will make reasonable efforts to contact the third party.

15.2 Early Restoration:

If permanent Service is terminated at the request of a Customer, whether or not the Service is disconnected by the Corporation, and if the same Customer requests restoration or reconnection of the Service to the premises on the same rate classification (or any replacement thereof) within 12 months, the Corporation shall require the Customer to pay the greater of:

- a) the expenses the Corporation incurred in making the restoration or reconnection of the Service; or
- b) the sum of the Demand charges which would have been paid by the Customer between the time of termination and the time of restoration or reconnection of the Service on the applicable rate.

16.0 **Termination of Service by Corporation**

16.1 Reasons of Safety:

The Corporation may, without notice, terminate Service to a Customer where, in the Corporation's opinion acting reasonably:

- a) the Customer's equipment or premises are unsafe or may become dangerous to life or property;
- b) the use of the Service may cause damage to the Corporation's Facilities, or interfere with, or disturb Service to any other Customer; or
- c) the Customer Facilities or any equipment of the Customer fail to comply with applicable statutes, regulations, standards and codes.

The Corporation will reconnect the Service when the safety problem is resolved, the Customer has provided the Corporation with an electrical inspection report of the

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Customer Facilities at the Customer's sole expense, the Corporation, acting reasonably, has approved such inspection report and the Customer has provided, or paid the Corporation's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

16.2 Without Notice:

The Corporation may, without notice, terminate a Customer's Service or install a current-limiting device to restrict the Service to such Customer where:

- a) the Customer is subject of bankrupt, insolvency or a similar proceeding, enters into receivership, or ceases to be a corporate entity;
- b) in the Corporation's opinion acting reasonably, tampering has occurred with any equipment used to provide Service, any meters, any seals, or any other Corporation Facilities;
- c) the Customer makes fraudulent use of the Service being provided; or
- d) the Customer changes Service requirements without the permission of the Corporation.

16.3 Non-payment:

Where accounts are not paid by a Customer within 7 days after the accounts become payable (a total of 28 days after the billing date), the Corporation may give a 48-hour notice of disconnection of Service, in writing to the Customer. Where accounts are not paid before the expiration of such notice, the Corporation may forthwith disconnect the Customer from Service.

Where the payment is received prior to the disconnection being completed is ultimately determined to be a dishonoured payment, the Corporation will not be required to initiate a second 48-hour disconnection notice and may proceed with disconnection action as appropriate.

Where accounts are not paid by a Customer before the expiration of a notice given

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to the Customer pursuant to this section, the Corporation may forthwith disconnect the Customer from Service and may refuse to reconnect the Customer for Service until the accounts in arrears, a security deposit payable under Sections 5.7 and 5.8, and a reconnection fee as set out in Schedule C are fully paid. As an alternative to disconnection during winter months, the Corporation may, at its sole discretion acting reasonably, install a device to limit the electricity available to the Customer.

16.4 Removal of Facilities:

Upon termination of Service, the Corporation shall be entitled to remove any of the Corporation Facilities located upon the property of the Customer and to enter upon the Customer's property for that purpose.

17 **Miscellaneous**

17.1 Waiver:

Any waiver by the Corporation, or failure of the Corporation, to exercise any of its remedies will be limited to the particular instance, and will not constitute a waiver of any other rights or remedy or extend to any other matter under, or in any way affect the validity or modify the meaning or intent of, any provisions of these terms. The exercise by the Corporation of any remedy provided for by these Terms will not operate to prevent the Corporation from pursuing any other remedy to which it is entitled.

17.2 Compliance with Applicable Legal Authorities:

The Corporation and the Customer are subject to, and shall comply with, all existing or future applicable federal, territorial and local laws, all existing or future orders or other actions of governmental authorities having jurisdiction.

17.3 No Assignment:

A Customer shall not assign any of its rights or obligations under the Terms without

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obtaining the Corporation's prior written consent. Any assignment in violation of this Section shall be void.

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SCHEDULE "A"

MAXIMUM CORPORATION INVESTMENT

1. "Capital Cost" is defined as the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Corporation in extending Service to a Point of Delivery.

"Annual Cost" is defined as including:

- a) the fixed annual amount of return and depreciation in respect of the Capital Cost of Facilities constructed to serve the Customer;
 - b) costs of generating and transmitting electric energy to the Customer, and operating and maintaining Facilities constructed to serve the Customer; and
 - c) administrative and general costs incurred by the Corporation in providing Service to the Customer.
-
2. Subject to the provisions of Section 3 of this Schedule "A", the maximum cost which the Corporation will incur to extend Service to a Point of Delivery (herein referred to as the "Maximum Corporation Investment") shall be determined as follows:
 - a) for Residential Service:
 - i) \$1,500 per single family dwelling;
 - ii) \$750 per unit in a Multiple Unit Dwelling;
 - b) for General Service;
 - i) where the estimated life of the Service Extension is at least 25 years, \$250 for each anticipated kilowatt (kW) of Billing Demand which shall not be less than 5 kW; or
 - ii) where the estimated life of the Service Extension is less than 25 years or where Service will be Seasonal, \$200 for each anticipated kW of Billing Demand (which shall not be less than 5 kW), multiplied by the amount determined by the following calculation:

Estimated number of months during which Service will be received

25 years X 12 months per year

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- (c) for Industrial Service, in the manner specified in an agreement with the Industrial Customer.
- 3. The Corporation will refund a portion of the construction contribution within three (3) years of the original service connection date, provided that:
 - a) actual kW demand is significantly higher than the kW demand used to determine the contribution and no changes have been made to the Facilities related to such contribution; or
 - b) another Customer shares a part of the service to which the construction contribution relates.
- 4. If the construction contribution refund is a result of an additional Customer applying within three (3) years of the original service connection date to be served from a service extension for which a construction contribution was originally made, the construction contribution will be reapportioned and refunds made as follows:
 - a) The Maximum Corporation Investment is re-evaluated by adding the costs of that portion of the dedicated facilities related to the original Customer to the portion of the dedicated facilities related to the additional Customer(s);
 - b) The Corporation's re-evaluated maximum investment is applied against the total costs of the shared service extension;
 - c) The difference between the Corporation's re-evaluated maximum investment and the total cost of the shared service extension is the total amount of the construction contribution required from the original Customer and the additional Customer(s);
 - d) The additional Customer(s) is then assessed an apportioned amount of the revised construction contribution required taking into consideration the portion of the original line that is now shared and the amount of time that has lapsed since the original service connection date of the original Customer serviced by the service extension (depreciation is based upon the Average

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Life Group method (ALG)); and

- e) The original contributor will be refunded the difference between the original construction contribution made and his portion of the revised total construction contribution required.

The refund program ceases to exist after Facilities have been in Service for a period of three (3) years from the time of the original Service connection.

The refund will be paid to the original contributor unless the Corporation is directed in writing by the original contributor to make the refund payable to another.

Action for the refund of capital contributions must be initiated by the original contributor.

If all or part of a contribution is subsequently refunded, the appropriate amount of GST originally collected will also be refunded.

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SCHEDULE "B"

CONDITIONS OF UNDERGROUND SERVICE

- 1). The Corporation shall extend Electricity Service by underground conductor lines upon and subject to the following terms and conditions (the term "developer" as used herein means the person or party who has requested the underground Service):
 - a) No Service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Corporation) will be connected to such extension (the "underground service area"), each of which is situated upon a parcel of land upon which other single family dwellings in the underground Service area are situated;
 - b) All permanent Service in the underground Service area shall be provided exclusively through underground conductor lines;
 - c) The developer shall provide, without cost to the Corporation, such rights-of-way, easements, utility corridors and transformer locations as the Corporation may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Corporation in installing, maintaining or removing its Facilities;
 - d) The Corporation shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Corporation in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;
 - e) Service, for purposes other than Residential use and Municipal Street Lighting, may be provided from such extension only with the consent of the Corporation;
 - f) In relation to the underground Service, the developer shall cause to be provided a meter receptacle and Service conductor protection from not less

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than 60 centimeters below grade level to the line side of the meter receptacle and will ensure the installation of a Service having 200 ampere capacity;

- g) The developer shall provide to the Corporation a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, and underground utilities together with such evidence as the Corporation may reasonably require to the effect that all rules and regulations applicable to the development have been or will be complied with by the developer;
- h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;
- i) The surface of the ground for a distance of not less than 1.5 metres on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;
- j) Unless otherwise agreed to by the Corporation, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required; and
- k) Sidewalks, curbs and gutters may be constructed by the developer but no other permanent improvements shall be made until approved by the Corporation.

In addition, the Service shall be subject to such other conditions as may be specified by the Corporation from time to time.

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SCHEDULE "C"

FEES AND SERVICE CHARGE SUMMARY

CONNECTION FEES

5.1 Residential Service Connection Fee	\$20.00
5.1 General Service Connection Fee (where a Demand Meter is Required)	40.00
5.1 Temporary Service Connection Fee	40.00
5.1 Seasonal Service Connection Fee	40.00
5.2 Reconnection Fee	40.00

5.8 Security Deposit

RESIDENTIAL SERVICE \$300.00

USER PAY \$100.00

GENERAL SERVICE

An estimate equal to the 2 months of billings with the highest consumption during the next 12 month period.

LATE PAYMENT AND DISCONNECTION

12.6 Late Payment Charge	1½ %/Month
12.4 Administration Fee for Commencing Collection Action	35.00
12.7 Dishonored Payments (as per Chartered Bank Charges)	25.00

Miscellaneous Fees/Charges

5.6 Power Bill Copying Charge	\$2.00 (via mail) \$3.00 (via fax)
11.3 Meter Accuracy Test-Deposit	\$75.00
11.3 Meter Accuracy Test-Fee (accurate meters only) TMI	
14.10 Service Call Response Fee	\$40.00 or TMI
7.5 Private Area Lighting Maintenance Fees	TMI
9.7 Service Extension Charges	As per Sched. "A"
9.9 Overhead to Underground Conversion	As per Sched "A"
9.10 Relocation of Facilities	TMI
2.33 TMI Deposit	
-50% of the estimated TMI or \$100.00 whichever is greater	
-If the estimated TMI is greater than \$5000.00 then the deposit = 75%	