NORFOLK POWER DISTRIBUTION INC. (Norfolk)

RESPONSES TO INTERROGATORIES

FROM

BOARD STAFF

1. Responses to Letters of Comment

Following publication of the Notice of Application, did Norfolk Power receive any letters of comment? If so, please confirm whether a reply was sent from Norfolk Power to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if Norfolk Power intends to respond.

Response:

Norfolk has not received any letters of comment.

2. Conditions of Service

a) Please identify any rates and charges that are included in Norfolk Power's Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

Response:

The Conditions of Service may reference that other charges/tariffs may be applicable, depending on the condition, but Norfolk doesn't publish any specific rates within the Cost of Service.

b) If any rates or charges are identified in part a), please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2010 and the revenue forecast for the 2011 bridge and 2012 test years.

Response:

Not applicable.

c) If any rates or charges are identified in part a), please explain whether in Norfolk Power's view, these rates and charges should be included on the Norfolk Power tariff sheet.

Response:

Not applicable.

3. Conditions of Service

How does Norfolk Power determine billing demand for General Service customers >50 kW, ie, the kW meter reading and/or 90% of the kVa demand? Is the method of billing documented in Norfolk Power's Conditions of Service?

Response:

Norfolk determines billing demand for General Service >50kW customers by applying the greater of the kW meter reading or 90% of the kVa demand. The method is not described in the Conditions of Service.

4. Revenue Requirement Work Form (RRWF)

The Revenue Requirement Work Form as filed by Norfolk Power with the application does not appear to be consistent with the values found in the body of the pre-filed evidence (ie, net fixed assets, rate base, etc) Please provide a revised RRWF with the appropriate entries.

Response:

Norfolk has filed a new RRWF with these responses. In the previous version filed accumulated depreciation was input incorrectly resulting in incorrect net fixed assets and rate base. In addition the tax rate was adjusted to reflect the effective tax rate.

5. Updated Revenue Requirement and RRWF

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that Norfolk Power wishes to make relative to the original application. In addition, please provide an updated RRWF with any corrections or adjustments that Norfolk Power wishes to make to the amounts in the previous version of the RRWF in the middle column.

Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Response:

Norfolk has submitted a revised RRWF in response to Board Staff Interrogatory #4 which reflects the original rate application. In the middle column of that RRWF adjustments have been made to reflect the following:

1. Norfolk has reduced the 2012 net book value of assets by $761,000 reflecting a reduced forecast for 2011 capital spending of the same amount. The details of this reduction in capital spending are available in Responses to Energy Probe #9 and #10.

2. Norfolk has reduced the 2012 depreciation expense by $17,416 as a result of the reduced capital spending in 2011.

3. Income tax credits have been increased by $10,000 for an additional apprentice tax credit, in response to Energy Probe #26.

4. Income taxes were adjusted as the result to the above changes from $321,258 to $302,537.

5. Revenue Offsets were adjusted to include the following:

	Original Offset	Revised Offset	Increase	Related Interrogatory
Rent from Affiliate	$9,600	$11,139	$1,539	Schools #17b
MicroFIT Revenue	$226	$5,130	$4,904	VECC #19 and Energy Probe #19
Total	$9,826	$16,269	$6,443	

In total, Service Revenue has been adjusted from the original application amount of $12,686,869 to $12,597,783.

Base Revenue Requirement has been reduced from $12,209,580 to $12,114,188.

6. Ref: Exhibit 1/Tab 3/Sch 2

At this reference, Norfolk Power indicates that for 2007, 2008, and 2009 it had not adopted the half-year rule for depreciation in the year of acquisition in its audited financial statements and has made an adjusting entry in 2010. Please provide a depreciation continuity table for the years 2007 to 2012 consistent with the tables found at Exhibit 2/Tab 2/Sch1 pages 1-5 that show the depreciation and net fixed asset values if the half-year adjustments referred to above had not been made and clearly show the impact on 2012 Rate Base in both CGAAP and IFRS.

Response:

Please note that the continuity schedules provided in Exhibit 2/Tab 2/Schedule 1, Pages 1-2 (2008 and 2009 Fixed Asset Continuity Schedules) show depreciation as it was actually calculated and reported (full year of depreciation on assets acquired in the year). Norfolk has provided "revised" tables for 2010, 2011 & 2012 under CGAAP, and for 2011 & 2012 under MIFRS as requested

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REVISED TABLE 2.4
Fixed Asset Continuity Schedule

Year Revised 2010 - No Half Year Rule

				Cost				Accumulated Depreciation - REVISED				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals / Adjustments	Closing Balance	Opening Balance	Additions	Disposals / Adjustments	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ -		$ 302,784	$ -	$ -		$ -	$ 302,784
47	1808	Buildings	2.00%	$ 1,615,717	$ 4,361		$ 1,620,078	-$ 149,866	-$ 32,402		-$ 182,267	$ 1,437,811
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 3,215,596	$ 5,696,787		$ 8,912,383	-$ 377,926	-$ 222,846		-$ 600,773	$ 8,311,611
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 4,120,928	$ 33,675	-$ 1,386,755	$ 2,767,848	-$ 1,691,662	-$ 87,864	$ 1,386,755	-$ 392,772	$ 2,375,076
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 25,698,012	$ 846,036	-$ 5,686,690	$ 20,857,358	-$ 12,098,600	-$ 865,199	$ 5,686,690	-$ 7,277,109	$ 13,580,249
47	1835	Overhead Conductors & Devices	4.00%	$ 13,715,614	$ 751,468	-$ 2,750,300	$ 11,716,783	-$ 5,405,305	-$ 468,671	$ 2,750,300	-$ 3,123,676	$ 8,593,107
47	1840	Underground Conduit	4.00%	$ 3,845,066	$ 160,329		$ 4,005,396	-$ 1,373,797	-$ 142,824		-$ 1,516,620	$ 2,488,775
47	1845	Underground Conductors & Devices	4.00%	$ 7,636,026	$ 255,331	-$ 1,204,925	$ 6,686,432	-$ 2,729,642	-$ 267,457	$ 1,204,925	-$ 1,792,174	$ 4,894,258
47	1850	Line Transformers	4.00%	$ 11,237,917	$ 744,525		$ 11,982,442	-$ 6,212,344	-$ 557,155		-$ 6,769,499	$ 5,212,942
47	1855	Services (Overhead & Underground)	4.00%	$ 2,507,308	$ 271,077		$ 2,778,385	-$ 432,561	-$ 111,135		-$ 543,696	$ 2,234,689
47	1860	Meters	4.00%	$ 4,025,165	$ 131,968		$ 4,157,133	-$ 2,229,621	-$ 158,335		-$ 2,387,956	$ 1,769,176
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,215,638	$ 91,650		$ 2,307,288	-$ 810,205	-$ 34,132		-$ 844,337	$ 1,462,951
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,223	-$ 640		-$ 3,863	$ 2,314
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 411,687	$ 5,958	-$ 264,715	$ 152,930	-$ 345,971	-$ 15,326	$ 264,715	-$ 96,582	$ 56,348
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 1,280,299	$ 44,046	-$ 609,419	$ 714,926	-$ 1,089,266	-$ 107,699	$ 609,419	-$ 587,546	$ 127,380
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 406,997	$ 35,884	-$ 147,109	$ 295,773	-$ 284,676	-$ 48,160	$ 147,109	-$ 185,728	$ 110,045
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 2,122,603	$ 75,784	-$ 659,750	$ 1,538,637	-$ 1,510,404	-$ 170,213	$ 659,750	-$ 1,020,867	$ 517,770
8	1935	Stores Equipment	10.00%	$ 120,335	$ 358	-$ 81,132	$ 39,562	-$ 102,515	-$ 3,956	$ 81,132	-$ 25,339	$ 14,223
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 727,933	$ 6,946	-$ 417,155	$ 317,724	-$ 573,406	-$ 31,772	$ 417,155	-$ 188,023	$ 129,701
8	1945	Measurement & Testing Equipment	10.00%	$ 178,973	$ 1,895		$ 180,868	-$ 93,994	-$ 18,087		-$ 112,081	$ 68,788
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 106,906	$ 1,021		$ 107,927	-$ 47,912	-$ 10,793		-$ 58,705	$ 49,222
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 412,334	$ 15,885		$ 428,220	-$ 100,640	-$ 42,822		-$ 143,462	$ 284,758
47	1975	Load Management Controls Utility Premises	N/A	$ 16,565	$ -	-$ 16,565	$ -	-$ 16,565	$ -	$ 16,565	$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 613,956	$ 540,685		$ 1,154,641	-$ 266,709	-$ 76,976		-$ 343,685	$ 810,956
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 12,653	$ 9,479		$ 22,132	-$ 4,522	-$ 4,426		-$ 8,948	$ 13,184
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 7,654,021	-$ 819,501		-$ 8,473,522	$ 1,638,433	$ 338,941		$ 1,977,374	-$ 6,496,148
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 5,019	-$ 1,004		-$ 6,023	$ 4,015
N/A	2055	Work In Progress	N/A	$ 5,472,038	-$ 5,472,038		$ -	$ -	$ -		$ -	$ -
		Total		**$ 85,016,144**	**$ 3,433,607**	**-$ 13,224,513**	**$ 75,225,237**	**-$ 36,317,916**	**-$ 3,140,953**	**$ 13,224,513**	**-$ 26,234,356**	**$ 48,990,881**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 170,213
Stores & Garage Equipment	-$ 33,682
Computer HW & SW	-$ 155,859
Net Depreciation to Inc. Stmt	**-$ 2,781,199**

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REVISED TABLE 2.5
Fixed Asset Continuity Schedule

Year **Revised 2011 Bridge - No Half Year** **GAAP**

				Cost				Accumulated Depreciation - REVISED				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 182,267	-$ 32,402		-$ 214,669	$ 1,405,409
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 600,773	-$ 222,846		-$ 823,619	$ 8,088,764
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,767,848	$ 75,000		$ 2,842,848	-$ 392,772	-$ 90,364		-$ 483,136	$ 2,359,712
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 20,857,358	$ 1,196,375		$ 22,053,733	-$ 7,277,109	-$ 913,054		-$ 8,190,163	$ 13,863,570
47	1835	Overhead Conductors & Devices	4.00%	$ 11,716,783	$ 849,912		$ 12,566,695	-$ 3,123,676	-$ 502,668		-$ 3,626,344	$ 8,940,351
47	1840	Underground Conduit	4.00%	$ 4,005,396	$ 220,000		$ 4,225,396	-$ 1,516,620	-$ 151,624		-$ 1,668,244	$ 2,557,152
47	1845	Underground Conductors & Devices	4.00%	$ 6,686,432	$ 388,000		$ 7,074,432	-$ 1,792,174	-$ 282,977		-$ 2,075,151	$ 4,999,281
47	1850	Line Transformers	4.00%	$ 11,982,442	$ 902,945		$ 12,885,387	-$ 6,769,499	-$ 370,322		-$ 7,139,822	$ 5,745,565
47	1855	Services (Overhead & Underground)	4.00%	$ 2,778,385	$ 268,108		$ 3,046,493	-$ 543,696	-$ 121,860		-$ 665,556	$ 2,380,937
47	1860	Meters	4.00%	$ 4,157,133	$ 72,000		$ 4,229,133	-$ 2,387,956	-$ 161,215		-$ 2,549,171	$ 1,679,962
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,307,288	$ 10,000		$ 2,317,288	-$ 844,337	-$ 34,332		-$ 878,669	$ 1,438,618
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,863	-$ 640		-$ 4,503	$ 1,674
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 152,930	$ 15,000		$ 167,930	-$ 96,582	-$ 15,267		-$ 111,849	$ 56,080
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 714,926	$ 30,000		$ 744,926	-$ 587,546	-$ 69,552		-$ 657,098	$ 87,828
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 295,773	$ 27,000		$ 322,773	-$ 185,728	-$ 41,847		-$ 227,575	$ 95,198
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 1,538,637	$ 440,000		$ 1,978,637	-$ 1,020,867	-$ 234,533		-$ 1,255,400	$ 723,237
8	1935	Stores Equipment	10.00%	$ 39,562	$ 1,000		$ 40,562	-$ 25,339	-$ 4,056		-$ 29,396	$ 11,166
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 317,724	$ 23,000		$ 340,724	-$ 188,023	-$ 33,167		-$ 221,190	$ 119,534
8	1945	Measurement & Testing Equipment	10.00%	$ 180,868	$ 6,000		$ 186,868	-$ 112,081	-$ 18,687		-$ 130,767	$ 56,101
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 107,927	$ 8,000		$ 115,927	-$ 58,705	-$ 11,593		-$ 70,298	$ 45,629
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 428,220	$ 5,000		$ 433,220	-$ 143,462	-$ 43,322		-$ 186,784	$ 246,436
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,154,641	$ 245,000		$ 1,399,641	-$ 343,685	-$ 93,309		-$ 436,995	$ 962,646
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132			$ 22,132	-$ 8,948	-$ 4,426		-$ 13,374	$ 8,757
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 8,473,522	-$ 861,340		-$ 9,334,862	$ 1,977,374	$ 373,394		$ 2,350,769	-$ 6,984,093
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 6,023	-$ 1,004		-$ 7,027	$ 3,012
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 75,225,237	$ 3,922,000	$ -	$ 79,147,237	-$ 26,234,356	-$ 3,081,673	$ -	-$ 29,316,029	$ 49,831,208

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 234,533
Stores & Garage Equipment	-$ 35,177
Computer HW & SW	-$ 111,400
Net Depreciation to Inc. Stmt	-$ 2,700,564

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REVISED TABLE 2.6
Fixed Asset Continuity Schedule

Year **Revised 2012 Test - Full Year Up to 2012** **GAAP**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 214,669	-$ 32,402		-$ 247,071	$ 1,373,007
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 823,619	-$ 222,846		-$ 1,046,465	$ 7,865,918
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,842,848	$ 275,000		$ 3,117,848	-$ 483,136	-$ 94,948		-$ 578,084	$ 2,539,764
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 22,053,733	$ 1,463,000		$ 23,516,733	-$ 8,190,163	-$ 942,314		-$ 9,132,477	$ 14,384,256
47	1835	Overhead Conductors & Devices	4.00%	$ 12,566,695	$ 925,000		$ 13,491,695	-$ 3,626,344	-$ 521,168		-$ 4,147,512	$ 9,344,183
47	1840	Underground Conduit	4.00%	$ 4,225,396	$ 100,000		$ 4,325,396	-$ 1,668,244	-$ 153,624		-$ 1,821,868	$ 2,503,528
47	1845	Underground Conductors & Devices	4.00%	$ 7,074,432	$ 203,000		$ 7,277,432	-$ 2,075,151	-$ 287,037		-$ 2,362,188	$ 4,915,244
47	1850	Line Transformers	4.00%	$ 12,885,387	$ 952,000		$ 13,837,387	-$ 7,139,822	-$ 317,405		-$ 7,457,227	$ 6,380,160
47	1855	Services (Overhead & Underground)	4.00%	$ 3,046,493	$ 375,000		$ 3,421,493	-$ 665,556	-$ 129,360		-$ 794,916	$ 2,626,577
47	1860	Meters	4.00%	$ 2,096,524	$ 348,000		$ 2,444,524	-$ 1,330,726	-$ 92,542		-$ 1,423,268	$ 1,021,255
47	1860	Meters (Smart Meters)	6.67%	$ 3,214,012	$ -		$ 3,214,012	-$ 586,005	-$ 214,267		-$ 800,272	$ 2,413,740
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,317,288	$ -		$ 2,317,288	-$ 878,669	-$ 34,332		-$ 913,001	$ 1,404,286
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 4,503	-$ 640		-$ 5,143	$ 1,034
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 167,930	$ 15,500		$ 183,430	-$ 111,849	-$ 13,490		-$ 125,339	$ 58,090
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 744,926	$ 40,000		$ 784,926	-$ 657,098	-$ 66,567		-$ 723,666	$ 61,260
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 322,773	$ 142,500		$ 465,273	-$ 227,575	-$ 50,503		-$ 278,078	$ 187,195
12	1925	Computer Software (Smart Meters)	20.00%	$ 406,373			$ 406,373	-$ 170,523	-$ 81,275		-$ 251,798	$ 154,575
10	1930	Transportation Equipment	10% to 25%	$ 1,978,637	$ 40,000		$ 2,018,637	-$ 1,255,400	-$ 202,476		-$ 1,457,876	$ 560,761
8	1935	Stores Equipment	10.00%	$ 40,562	$ 1,000		$ 41,562	-$ 29,396	-$ 3,223		-$ 32,619	$ 8,943
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 340,724	$ 20,000		$ 360,724	-$ 221,190	-$ 29,707		-$ 250,897	$ 109,827
8	1945	Measurement & Testing Equipment	10.00%	$ 186,868	$ 2,000		$ 188,868	-$ 130,767	-$ 13,871		-$ 144,638	$ 44,230
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 115,927	$ 53,000		$ 168,927	-$ 70,298	-$ 12,197		-$ 82,495	$ 86,432
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 433,220	$ 5,000		$ 438,220	-$ 186,784	-$ 43,572		-$ 230,356	$ 207,864
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,399,641	$ 100,000		$ 1,499,641	-$ 436,995	-$ 96,643		-$ 533,638	$ 966,003
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 13,374	-$ 4,426		-$ 17,800	$ 4,331
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 9,334,862	-$ 652,000		-$ 9,986,862	$ 2,350,769	$ 386,434		$ 2,737,203	-$ 7,249,659
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 7,027	-$ 1,004		-$ 8,031	$ 2,008
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 80,635,013	$ 4,408,000	$ -	$ 85,043,013	-$ 28,854,112	-$ 3,275,406	$ -	-$ 32,129,519	$ 52,913,495

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 202,476
Stores & Garage Equipment	-$ 30,884
Computer HW & SW	-$ 117,070
Net Depreciation to Inc. Stmt	-$ 2,924,976

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REVISED TABLE 5.1
Fixed Asset Continuity Schedule

Year **2011 Bridge - No Half-Yr Rule** **IFRS**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights	N/A	$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,437,811	$ -		$ 1,437,811	$ -	-$ 33,076		-$ 33,076	$ 1,404,735
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.5% to 5%	$ 8,311,611	$ -		$ 8,311,611	$ -	-$ 230,363		-$ 230,363	$ 8,081,248
47	1820	Distribution Station Equipment <50 kV	5.00%	$ 2,375,076	$ 65,131		$ 2,440,207	$ -	-$ 159,301		-$ 159,301	$ 2,280,906
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	2.20%	$ 13,580,249	$ 1,038,945		$ 14,619,194	$ -	-$ 404,922		-$ 404,922	$ 14,214,272
47	1835	Overhead Conductors & Devices	1.6% to 2.5%	$ 8,593,107	$ 738,072		$ 9,331,179	$ -	-$ 197,291		-$ 197,291	$ 9,133,888
47	1840	Underground Conduit	2.00%	$ 2,488,775	$ 191,050		$ 2,679,825	$ -	-$ 61,811		-$ 61,811	$ 2,618,015
47	1845	Underground Conductors & Devices	3.33%	$ 4,894,258	$ 336,943		$ 5,231,201	$ -	-$ 223,708		-$ 223,708	$ 5,007,493
47	1850	Line Transformers	2.5% to 2.8%	$ 5,212,942	$ 784,127		$ 5,997,069	$ -	-$ 182,895		-$ 182,895	$ 5,814,175
47	1855	Services (Overhead & Underground)	2.50%	$ 2,234,689	$ 232,828		$ 2,467,517	$ -	-$ 69,245		-$ 69,245	$ 2,398,272
47	1860	Meters	3.33% to 4%	$ 1,769,176	$ 62,526		$ 1,831,702	$ -	-$ 98,280		-$ 98,280	$ 1,733,422
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 1,462,951	$ 10,000		$ 1,472,951	$ -	-$ 54,993		-$ 54,993	$ 1,417,958
13	1910	Leasehold Improvements	10.00%	$ 2,314	$ -		$ 2,314	$ -	-$ 654		-$ 654	$ 1,660
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 56,348	$ 15,000		$ 71,348	$ -	-$ 15,267		-$ 15,267	$ 56,080
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	25.00%	$ 127,380	$ 30,000		$ 157,380	$ -	-$ 54,688		-$ 54,688	$ 102,692
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 110,045	$ 27,000		$ 137,045	$ -	-$ 38,346		-$ 38,346	$ 98,699
12	1925	Computer Software (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	6.6% to 14.3%	$ 517,770	$ 440,000		$ 957,770	$ -	-$ 95,299		-$ 95,299	$ 862,471
8	1935	Stores Equipment	10.00%	$ 14,223	$ -		$ 14,223	$ -	-$ 3,956		-$ 3,956	$ 10,267
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 129,701	$ 35,000		$ 164,701	$ -	-$ 33,495		-$ 33,495	$ 131,206
8	1945	Measurement & Testing Equipment	20.00%	$ 68,788	$ -	-$ 42,514	$ 26,274	$ -	-$ 11,923		-$ 11,923	$ 14,351
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	20.00%	$ 49,222	$ 8,000	-$ 13,133	$ 44,089	$ -	-$ 23,051		-$ 23,051	$ 21,039
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	20.00%	$ 284,758	$ -	-$ 33,857	$ 250,901	$ -	-$ 94,300		-$ 94,300	$ 156,600
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	5.00%	$ 824,140	$ 212,761		$ 1,036,901	$ -	-$ 62,324		-$ 62,324	$ 974,576
45.1	1980	System Supervisor Equipment - Hardware	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	various	-$ 6,496,148	-$ 861,340		-$ 7,357,488	$ -	$ 202,725		$ 202,725	-$ 7,154,764
8	2005	Property Under Capital Lease	10.00%	$ 4,015	$ -		$ 4,015	$ -	-$ 1,004		-$ 1,004	$ 3,012
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 48,990,880	$ 3,367,043	-$ 89,504	$ 52,268,419	$ -	-$ 1,947,469	$ -	-$ 1,947,469	$ 50,320,951

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 95,299
Stores & Garage Equipment	-$ 38,456
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	-$ 1,813,714

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REVISED TABLE 5.2
Fixed Asset Continuity Schedule

Year 2012 Test - Adopt Half Year Rule in 2012 **IFRS**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,437,811	$ -		$ 1,437,811	-$ 33,076	-$ 33,076		-$ 66,153	$ 1,371,658
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.5% to 5%	$ 8,311,611	$ -		$ 8,311,611	-$ 230,363	-$ 230,363		-$ 460,725	$ 7,850,885
47	1820	Distribution Station Equipment <50 kV	5.00%	$ 2,440,207	$ 245,564		$ 2,685,771	-$ 159,301	-$ 165,440		-$ 324,742	$ 2,361,029
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	2.20%	$ 14,619,194	$ 1,306,399		$ 15,925,593	-$ 404,922	-$ 442,525		-$ 847,447	$ 15,078,146
47	1835	Overhead Conductors & Devices	1.6% to 2.5%	$ 9,331,179	$ 825,987		$ 10,157,166	-$ 197,291	-$ 212,601		-$ 409,892	$ 9,747,274
47	1840	Underground Conduit	2.00%	$ 2,679,825	$ 89,296		$ 2,769,121	-$ 61,811	-$ 66,525		-$ 128,336	$ 2,640,786
47	1845	Underground Conductors & Devices	3.33%	$ 5,231,201	$ 181,271		$ 5,412,472	-$ 223,708	-$ 237,961		-$ 461,669	$ 4,950,803
47	1850	Line Transformers	2.5% to 2.8%	$ 5,997,069	$ 850,097		$ 6,847,166	-$ 182,895	-$ 213,124		-$ 396,019	$ 6,451,148
47	1855	Services (Overhead & Underground)	2.50%	$ 2,467,517	$ 334,860		$ 2,802,377	-$ 69,245	-$ 79,251		-$ 148,496	$ 2,653,880
47	1860	Meters	3.33% to 4%	$ 1,831,702	$ 310,750	-$ 907,587	$ 1,234,865	-$ 98,280	-$ 52,860	$ 53,197	-$ 97,944	$ 1,136,922
47	1860	Meters (Smart Meters)	10.00%	$ 3,214,012	$ -		$ 3,214,012	-$ 479,090	-$ 368,399		-$ 847,489	$ 2,366,523
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 1,472,951	$ -		$ 1,472,951	-$ 54,993	-$ 55,159		-$ 110,152	$ 1,362,799
13	1910	Leasehold Improvements	10.00%	$ 2,314	$ -		$ 2,314	-$ 654	-$ 654		-$ 1,308	$ 1,006
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 71,348	$ 15,500		$ 86,848	-$ 15,267	-$ 13,490		-$ 28,757	$ 58,091
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	25.00%	$ 157,380	$ 40,000		$ 197,380	-$ 54,688	-$ 67,188		-$ 121,877	$ 75,503
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 137,045	$ 142,500		$ 279,545	-$ 38,346	-$ 47,196		-$ 85,543	$ 194,002
12	1925	Computer Software (Smart Meters)	20.00%	$ 406,373	$ -		$ 406,373	-$ 129,885	-$ 80,212		-$ 210,097	$ 196,276
10	1930	Transportation Equipment	6.6% to 14.3%	$ 957,770	$ 40,000		$ 997,770	-$ 95,299	-$ 125,966		-$ 221,265	$ 776,505
8	1935	Stores Equipment	10.00%	$ 14,223	$ -		$ 14,223	-$ 3,956	-$ 3,073		-$ 7,029	$ 7,193
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 164,701	$ 28,000		$ 192,701	-$ 33,495	-$ 33,935		-$ 67,431	$ 125,270
8	1945	Measurement & Testing Equipment	20.00%	$ 26,274	$ -		$ 26,274	-$ 11,923	-$ 9,163		-$ 21,086	$ 5,188
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	20.00%	$ 44,089	$ 53,000		$ 97,089	-$ 23,051	-$ 21,079		-$ 44,130	$ 52,959
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	20.00%	$ 250,901	$ -		$ 250,901	-$ 94,300	-$ 84,313		-$ 178,613	$ 72,288
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	5.00%	$ 1,036,901	$ 89,296		$ 1,126,197	-$ 62,324	-$ 75,195		-$ 137,519	$ 988,678
45.1	1980	System Supervisor Equipment - Hardware	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	various	-$ 7,357,488	-$ 652,000		-$ 8,009,488	$ 202,725	$ 217,251		$ 419,975	-$ 7,589,513
8	2005	Property Under Capital Lease	10.00%	$ 4,015	$ -		$ 4,015	-$ 1,004	-$ 1,004		-$ 2,008	$ 2,008
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 55,888,804**	**$ 3,900,520**	**-$ 907,587**	**$ 58,881,737**	**-$ 2,556,444**	**-$ 2,502,502**	**$ 53,197**	**-$ 5,005,749**	**$ 53,875,988**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 125,966
Stores & Garage Equipment	-$ 35,533
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 2,341,003**

Norfolk has provided 2012 in CGAAP & MIFRS assuming adoption of the half year rule for additions in the year 2012 (see Norfolk's response to EP #6(c) which required Norfolk to provide a fixed asset continuity schedule for 2012 assuming the half-year rule was adopted for 2012).

Below is a table showing the impact on 2012 Rate Base if Norfolk had not adopted the half-year rule for depreciation on current year additions until the year 2012:

Impact of MIFRS on Net Book Value (Full-Year Rule 2007 to 2011)

	2012 Test (CGAAP) as Submitted - Revised for 2012 Deprec Exp on 1860	2012 Test (CGAAP) Full-Year Amortization 2007 to 2011	Variance - CGAAP (Half-Year vs. Full-Year)	2012 Test (MIFRS) as Submitted	2012 Test (MIFRS) Full-Year Amortization 2007 to 2011	Variance - MIFRS (Half-Year vs. Full-Year)
Gross Fixed Assets	$84,994,791	$85,043,013		$59,274,191	$58,881,737	
Accumulated Depreciation	$31,406,039	$32,129,519		$4,984,969	$5,005,749	
NET BOOK VALUE	**$53,588,752**	**$52,913,494**		**$54,289,222**	**$53,875,988**	
Average Net Book Value	***$53,029,585***	***$52,437,958***		***$53,568,246***	***$53,176,980***	
Working Capital Allowance (15%)	$5,992,935	$5,992,935		$6,085,418	$6,085,418	
RATE BASE	**$59,022,520**	**$58,430,893**	**($591,627)**	**$59,653,664**	**$59,262,398**	**($391,266)**

Average Net Book Value for 2012 MIFRS:

2011 Revised NBV - IFRS (Rev Table 5.1)	**$50,320,951**
Less: Stranded Meters (NBV)	**($854,390)**
Add: Smart Meters & SM S/W (NBV)	**$3,011,410**
Adjusted 2012 Opening Balance	**$52,477,971**
2012 Revised NBV - IFRS (Rev Table 5.2)	**$53,875,988**
Average Net Book Value	**$53,176,980**

7. Ref: Exhibit 2/Tab 1/Sch 1/p. 7

In this summary under Substations, Norfolk Power indicates that, "The renewal or retirement of NPDI's 4.16 kV and 8.32 kV substations is the subject of an ongoing review being undertaken as part of the Asset Management Plan. NPDI has been expanding their 27.6 kV system for several years with the objective of eliminating much of the 4.16 kV network, which will eventually lead to a reduction in the number of distribution stations, a reduction in the number of distribution feeders, and improved electricity distribution efficiency."

How much of the older 4.16 kV and 8.32 kV system has been replaced with the newer 27.6 kV system? How was this issue addressed in the Asset Management Plan review? Is there an end date for when the 4.16 kV system is to be entirely replaced?

Response:

To date, Norfolk Power has converted approximately 4.9% of the 4kV system with 27.6kV distribution circuits and has renewed 2 of 7, 8kV Municipal Distribution Stations.

Voltage conversion projects are addressed in the Asset Management Plan under "Security and Asset Renewal" reviews, and are noted in the Prioritization Criteria.

The intent to convert the 4.16 kV system has been incorporated into Norfolk Power's capital plans and has an anticipated end date of 2020. There is currently no formal plan to convert the 8.32kV system.

8. Ref: Exhibit 2/Tab 1/Sch 1/p. 7

In this summary under Customer Connections and Metering, Norfolk Power indicates that, "In 2009 NPDI began installation of smart meters and will complete the program in 2011." However, the 2010 Financial Statements, at page 15, indicate that, "As at December 31, 2010, all residential and small commercial customers have had smart meters installed." Please reconcile these two statements and provide a current update on Norfolk Power's Smart Meter deployment.

Response:

The comment taken from page 15 of the 2010 Financial Statements is incorrect and appears to have stemmed from a conversation in which Norfolk had stated it had installed all of the smart meters it could at that time (at the end of 2010) as Norfolk was waiting for additional smart meters to be delivered. There had been a delay in delivery of meters for sometime as a result of a delay in manufacturing and meters that had been originally anticipated to arrive in 2010 did not arrive until March 2011.

As of the end of September 2011 Norfolk had installed 18,288 smart meters, with a balance of 515 meters to be installed by the end of 2011.

9. Ref: Exhibit 2/Tab 3/Sch 2/p.31

Under the category of Miscellaneous Overhead Projects for 2010, 2011 and 2012 Norfolk Power indicates these are reactive renewal projects of overhead system assets with a "run to failure" replacement strategy.

Please explain Norfolk Power's position on a capital replacement strategy based on "run to failure". How much of the Norfolk Power system is governed by this strategy and how is it coordinated with the Asset Management Plan?

Response:

To some extent, Norfolk's system renewal is governed by the "run to failure" philosophy, as some assets are difficult and/or costly to test and inspect proactively including distribution transformers and underground cable. Reactive replacement (ie – run to failure) of assets occurs as assets fail or pose a safety hazard to the public. Funds designated under the Miscellaneous Overhead Projects cover these unforeseen occurrences.

Proactive replacement occurs when assets nearing end of lives are removed from service and are replaced systematically according to the asset management plan. These projects are reflected in the annual capital spending plans as specific projects. In general, most major asset types are addressed in the renewal plans for replacement in the asset management plan, as their life expectancies are reviewed using a combination of inspection and condition assessment reports, fault exposure experience, loading and useful life criteria. It is difficult to specifically quantify the degree of plant which is replaced via "run to failure" strategy. Norfolk strives to replace plant on a planned basis.

MIFRS Related

10. Ref: Exhibit 2/Tab 5/Sch 1

In the Letter of the Board regarding Transition to IFRS – Amendment to Board Policy, November 8, 2010, the Board stated:

"9.1.2 Electricity distributors filing cost of service applications for rates in the year they choose to adopt IFRS for financial reporting must provide the required actual years, the bridge year and the forecasts for the test year(s) in CGAAP based format. An electricity distributor may choose to present modified IFRS based forecasts for the bridge and test years, if the distributor seeks to have rates set on the basis of modified IFRS. If the distributor is seeking rates based on modified IFRS accounting, the distributor must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting."

The Board also stated on page 14 of the July 2009 Report of the Board, Transition to IFRS:

"The Board agrees that regulated net book value should be used as the basis for setting opening rate base values upon the adoption of IFRS accounting, and that historical acquisition cost should be used as the basis for reporting PP&E for regulatory purposes going forward."4

For financial reporting purposes, on the date of transition to IFRS, the December 31, 2010 net book value becomes the January 1, 2011 gross value for PP&E (with accumulated depreciation set to zero). However, the Board has stated that the integrity of the December 31, 2010 gross value and accumulated depreciation values should be preserved for regulatory purposes and carried forward to January 1, 2011 values.

The continuity of historic cost should be established by Norfolk Power by using the December 31, 2010 regulatory gross capital cost and accumulated depreciation values as the opening January 1, 2011 regulatory gross capital cost and accumulated depreciation values.

Norfolk Power has filed for 2012 rates based on MIFRS. Board staff would like additional information to complete the record. Please provide the following:

a) The Bridge Year in MIFRS, maintaining asset continuity by using the December 31, 2010 regulatory gross capital and accumulated depreciation as the opening January 1, 2011 regulatory gross capital cost and accumulated depreciation values;

Response:

Norfolk believes it has met the requirement of the Board as described in the July 2009 Report of the Board, Transition to IFRS, by maintaining the integrity of the regulated net book value for the purpose of establishing opening rate base values under IFRS.

Norfolk has also provided the Bridge Year in MIFRS while maintaining the gross capital and accumulated depreciation as requested. Please see the response to Interrogatory 10(e) – 2011 Bridge Fixed Asset Continuity Statement in IFRS.

b) The Test Year with the opening balances based on the closing Bridge Year balances based on MIFRS from a) above;

Response:

Please see Norfolk's response to Interrogatory 10(e) – 2012 Test Fixed Asset Continuity Statement in IFRS.

c) The Test Year in CGAAP-based format;

Response:

Norfolk provided the Test Year Fixed Asset Continuity Schedule in CGAAP-based format in its original submission (found at Exhibit 2, Tab 5, Schedule 1, Table 2.6), as well as in the Chapter 2 Filing Requirements Excel file, Appendix 2-B.

d) Two RRWFs for the Test Year, one based on CGAAP, and one based on MIFRS;

Response:

A RRWF based on MIFRS was submitted with the application and has been resubmitted with these interrogatories to correct an error as noted in the response to Board Staff Interrogatory #4.

A RRWF based on CGAAP has also been submitted as requested.

e) Updated Appendix 2-B Fixed Asset Continuity Schedule of the chapter 2 filing requirements; and

Response:

Norfolk has provided the updated Appendix 2-B Fixed Asset Continuity Schedule of the chapter 2 filing requirements with the submission of these replies.

Please also See Appendix 1 Fixed Asset Continuity Schedule Board Staff IR 10e.

BOARD STAFF #10(e)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011 Bridge** **IFRS** *REVISED TO SHOW FULL GROSS ASSET & ACCUMULATED DEPRECIATION*

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 180,575	-$ 33,112		-$ 213,687	$ 1,406,391
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 524,387	-$ 232,330		-$ 756,717	$ 8,155,666
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,767,848	$ 65,131		$ 2,832,979	-$ 363,334	-$ 161,059		-$ 524,393	$ 2,308,586
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 20,857,358	$ 1,038,945		$ 21,896,303	-$ 7,198,276	-$ 395,240		-$ 7,593,517	$ 14,302,786
47	1835	Overhead Conductors & Devices	4.00%	$ 11,716,783	$ 738,072		$ 12,454,855	-$ 3,056,012	-$ 191,773		-$ 3,247,785	$ 9,207,070
47	1840	Underground Conduit	4.00%	$ 4,005,396	$ 191,050		$ 4,196,446	-$ 1,501,837	-$ 60,211		-$ 1,562,048	$ 2,634,397
47	1845	Underground Conductors & Devices	4.00%	$ 6,686,432	$ 336,943		$ 7,023,375	-$ 1,763,071	-$ 219,158		-$ 1,982,229	$ 5,041,146
47	1850	Line Transformers	4.00%	$ 11,982,442	$ 784,127		$ 12,766,569	-$ 6,710,564	-$ 174,804		-$ 6,885,368	$ 5,881,200
47	1855	Services (Overhead & Underground)	4.00%	$ 2,778,385	$ 232,828		$ 3,011,213	-$ 520,375	-$ 66,958		-$ 587,333	$ 2,423,880
47	1860	Meters	4.00%	$ 4,157,133	$ 62,526		$ 4,219,659	-$ 2,375,136	-$ 97,707		-$ 2,472,843	$ 1,746,815
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,307,288	$ 10,000		$ 2,317,288	-$ 840,742	-$ 101,372		-$ 942,114	$ 1,375,174
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,863	-$ 654		-$ 4,517	$ 1,660
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 152,930	$ 15,000		$ 167,930	-$ 94,521	-$ 15,568		-$ 110,089	$ 57,841
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 714,926	$ 30,000		$ 744,926	-$ 555,770	-$ 63,095		-$ 618,865	$ 126,061
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 295,773	$ 27,000		$ 322,773	-$ 173,001	-$ 37,574		-$ 210,575	$ 112,197
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 1,538,637	$ 440,000		$ 1,978,637	-$ 1,062,530	-$ 82,451		-$ 1,144,981	$ 833,656
8	1935	Stores Equipment	10.00%	$ 39,562	$ -		$ 39,562	-$ 25,115	-$ 3,990		-$ 29,105	$ 10,457
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 317,724	$ 35,000		$ 352,724	-$ 184,305	-$ 32,269		-$ 216,574	$ 136,150
8	1945	Measurement & Testing Equipment	10.00%	$ 180,868	$ -	-$ 42,514	$ 138,354	-$ 110,314	-$ 12,762		-$ 123,076	$ 15,278
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 107,927	$ 8,000	-$ 13,133	$ 102,794	-$ 56,055	-$ 23,866		-$ 79,921	$ 22,873
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 428,220	$ -	-$ 33,857	$ 394,363	-$ 129,028	-$ 99,699		-$ 228,727	$ 165,636
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,154,641	$ 212,761		$ 1,367,402	-$ 325,599	-$ 57,234		-$ 382,833	$ 984,569
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 6,735	-$ 847		-$ 7,582	$ 14,550
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 8,473,522	-$ 861,340		-$ 9,334,862	$ 1,931,842	$ 193,818		$ 2,125,660	-$ 7,209,201
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 6,023	-$ 1,004		-$ 7,027	$ 3,011
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 75,225,237	$ 3,367,043	-$ 89,504	$ 78,502,776	-$ 25,835,326	-$ 1,970,919	$ -	-$ 27,806,246	$ 50,696,531

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 82,451
Stores & Garage Equipment	-$ 37,263
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	-$ 1,851,205

BOARD STAFF #10(e)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012 Test** **IFRS** *REVISED TO SHOW FULL GROSS ASSET & ACCUMULATED DEPRECIATION*

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance (Adjusted for Smart Meters & Stranded Meters)	Additions	Disposals	Closing Balance	Opening Balance (Adjusted for Smart Meters & Stranded Meters)	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 213,687	-$ 33,112		-$ 246,799	$ 1,373,279
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 756,717	-$ 232,330		-$ 989,047	$ 7,923,336
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,832,979	$ 245,564		$ 3,078,543	-$ 524,393	-$ 167,198		-$ 691,591	$ 2,386,952
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 21,896,303	$ 1,306,399		$ 23,202,702	-$ 7,593,517	-$ 421,300		-$ 8,014,817	$ 15,187,885
47	1835	Overhead Conductors & Devices	4.00%	$ 12,454,855	$ 825,987		$ 13,280,842	-$ 3,247,785	-$ 199,428		-$ 3,447,213	$ 9,833,629
47	1840	Underground Conduit	4.00%	$ 4,196,446	$ 89,296		$ 4,285,742	-$ 1,562,048	-$ 63,015		-$ 1,625,063	$ 2,660,678
47	1845	Underground Conductors & Devices	4.00%	$ 7,023,375	$ 181,271		$ 7,204,646	-$ 1,982,229	-$ 227,795		-$ 2,210,024	$ 4,994,622
47	1850	Line Transformers	4.00%	$ 12,766,569	$ 850,097		$ 13,616,666	-$ 6,885,368	-$ 195,231		-$ 7,080,599	$ 6,536,066
47	1855	Services (Overhead & Underground)	4.00%	$ 3,011,213	$ 334,860		$ 3,346,073	-$ 587,333	-$ 74,055		-$ 661,388	$ 2,684,685
47	1860	Meters	4.00%	$ 2,087,050	$ 310,750		$ 2,397,800	-$ 1,200,905	-$ 50,876		-$ 1,251,781	$ 1,146,018
47	1860	Meters (Smart Meters)	10.00%	$ 3,214,012	$ -		$ 3,214,012	-$ 479,090	-$ 321,401		-$ 800,491	$ 2,413,521
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,317,288	$ -		$ 2,317,288	-$ 942,114	-$ 101,472		-$ 1,043,586	$ 1,273,702
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 4,517	-$ 654		-$ 5,171	$ 1,006
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 167,930	$ 15,500		$ 183,430	-$ 110,089	-$ 13,790		-$ 123,879	$ 59,551
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 744,926	$ 40,000		$ 784,926	-$ 618,865	-$ 93,720		-$ 712,585	$ 72,341
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 322,773	$ 142,500		$ 465,273	-$ 210,575	-$ 47,211		-$ 257,786	$ 207,486
12	1925	Computer Software (Smart Meters)	25.00%	$ 406,373	$ -		$ 406,373	-$ 129,885	-$ 101,593		-$ 231,478	$ 174,895
10	1930	Transportation Equipment	10% to 25%	$ 1,978,637	$ 40,000		$ 2,018,637	-$ 1,144,981	-$ 98,451		-$ 1,243,432	$ 775,205
8	1935	Stores Equipment	10.00%	$ 39,562	$ -		$ 39,562	-$ 29,105	-$ 3,107		-$ 32,212	$ 7,350
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 352,724	$ 28,000		$ 380,724	-$ 216,574	-$ 30,959		-$ 247,533	$ 133,191
8	1945	Measurement & Testing Equipment	10.00%	$ 138,354	$ -		$ 138,354	-$ 123,076	-$ 9,772		-$ 132,848	$ 5,506
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 102,794	$ 53,000		$ 155,794	-$ 79,921	-$ 22,089		-$ 102,010	$ 53,784
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 394,363	$ -		$ 394,363	-$ 228,727	-$ 88,879		-$ 317,606	$ 76,757
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,367,402	$ 89,296		$ 1,456,698	-$ 382,833	-$ 64,785		-$ 447,618	$ 1,009,080
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 7,582	-$ 847		-$ 8,429	$ 13,703
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 9,334,862	-$ 652,000		-$ 9,986,862	$ 2,125,660	$ 205,507		$ 2,331,167	-$ 7,655,694
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 7,027	-$ 1,004		-$ 8,031	$ 2,007
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 79,990,552**	**$ 3,900,520**	**$ -**	**$ 83,891,072**	**-$ 27,143,283**	**-$ 2,458,567**	**$ -**	**-$ 29,601,850**	**$ 54,289,222**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 98,451
Stores & Garage Equipment	-$ 32,591
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 2,327,525**

f) A summary of the dollar impacts of MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall impact on the proposed revenue requirement.

Response:

Norfolk has provided the following table indicating the impact of MIFRS on each major component of the revenue requirement. The total impact of MIFRS on Revenue Requirement is a decrease of $168,634.

Summary of MIFRS impact on Revenue Requirement

	2012 CGAAP	2012 MIFRS	Variance
Distribution Revenue	$12,378,214	$12,209,580	-$168,634
Other Operating Revenue	477,289	477,289	
Total Revenue	12,855,503	12,686,869	-168,634
OM&A	5,236,062	5,852,617	616,555
Depreciation	2,926,650	2,327,524	-599,126
Deemed Interest	1,878,233	1,899,543	21,310
Income Tax (PILs)	554,275	321,256	-233,019
Net Income (Deemed Return)	2,260,283	2,285,928	25,645
Rate Base	58,984,431	59,653,664	669,233
Deemed Debt	35,390,659	35,792,198	401,540
Deemed Equity	23,593,772	23,861,466	267,693
Return on Debt (Weighted)	5.31%	5.31%	
Return on Equity	9.58%	9.58%	
Deemed Interest Expense	1,878,233	1,899,543	21,310
Deemed Return on Equity	2,260,283	2,285,928	25,645

11. Ref: Exhibit 2/Tab 5/Sch 1

In the Letter of the Board regarding Transition to IFRS – Amendment to Board Policy, November 8, 2010, the Board stated on page 15:

"The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS."

IAS 16 Property, Plant and Equipment states that the cost of PP&E comprises of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. The Board also said on page 40:

"The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates."

Board staff is interested in the impact of MIFRS on Norfolk Power's capital expenditures.

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

Response:

The capital expenditure forecasts for 2011 and 2012 under MIFRS of the application include only directly attributable costs.

b) Has Norfolk Power consulted with its external auditors or professional advisors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify if there is any plan in the near future for such a consultation.

Response:

Norfolk engaged KPMG to assist with several areas of the conversion to IFRS, including the changes required by IAS 16 and IAS 23. In addition, Norfolk has reviewed the changes, as outlined in the application, to convert from CGAAP to MIFRS, with its external auditors at

Millard, Rouse & Rosebrugh. Letters from both KPMG and Millard, Rouse & Rosebrugh, confirming their participation, have been included with these interrogatory responses as Appendix 2.

Please see Appendix 2 External Review - IFRS Board Staff IR 11b.

c) Please identify all overhead related items (e.g. indirect costs, corporate centre costs) and identify the items that are ineligible and how much overhead in total has been removed from capitalization for ineligible costs.

Response:

Norfolk utilizes 4 burdens to allocate overhead related items to expense accounts and capital projects. These include Payroll, Engineering, Fleet, and Stores. Norfolk has recognized that where CGAAP allowed for the capitalization of general and administrative overhead, MIFRS does not and as a result Norfolk has identified several items included in its overhead burdens that will be expensed as part of OM&A rather than capitalized. A full explanation of these expenses is provided in the application and can be found in Exhibit 4, Tab 4, Schedule 1.

In Appendix 4 Norfolk has provided a Conclusion Document prepared with the aid of KPMG that outlines the expenses in Norfolk's burdens and those that will be removed and expensed as part of OM&A under IFRS. This document does not provide the financial impact of these changes, however Norfolk's application does provide these details under Exhibit 4, Tab 4, Schedule 1. For convenience Norfolk has summarized these values below.

Payroll - $95,864 in expenses related to training, safety and education expenses has been removed from the payroll burden.

Engineering – The following amounts have been removed from the engineering burden:

Supervisory & Admin Labour	$216,409
IT Charges	114,320
Property Charges	13,239
Total	$343,968

Fleet – the following amounts have been removed from the fleet burden:

Miscellaneous Tools	$ 9,000
Property Charges	36,000
Total	$45,300

Stores – the following amounts have been removed from the Stores burden:

Supervisory Labour	$ 7,113
IT Charges	20,520
Property Charges	103,790
Total	$131,423

Total expenses removed from capitalized burdens and added to OM&A: $616,555.

Please see Appendix 3 Conclusion Document IAS 16 PPE Burdens Board Staff IR 11c.

d) Please identify the burden rates related to the capitalization of costs of self-constructed assets:

i) Prior to transition (from the last rebasing application to January 1, 2011), and

Response:

Burden	2008	2009	2010	2011 YTD
Stores	41%	36%	37%	30%
Fleet	$10/hr passenger vehicles, $30/hr large trucks	$10/hr passenger vehicles, $30/hr large trucks	$13/hr passenger vehicles, $40/hr large trucks	$14/hr passenger vehicles, $44/hr large trucks
Payroll	64%	62%	60%	64%
Engineering	34%	28%	35%	30%

ii) After transition (on or after January 1, 2011).

Response:

Payroll Burden: 56%

Engineering: 21%

Stores: 16%

Fleet: Truck rates remain the same at $14 per hour for small vehicles and $44 per hour for large vehicles.

e) Please provide the following information in detail for overhead costs on self-constructed assets for the bridge and test years.

Response:

Please see table below:

Nature of the Overhead Costs	Dollar Impact Bridge Year	Dollar Impact Test Year	Directly Attributable: Yes or No	Reasons for Capitalization under MIFRS
Engineering:				
Labour	$ 423,000	$ 433,300	Yes	Internal labour directly attributable to capital projects
Total	**$ 423,000**	**$ 433,300**		
Stores:				
Stores Labour	$ 101,352	$ 72,054	Yes	Storekeepers' time directly attributable to inventory items relating to specific capital projects
Purchasing Labour	$ 45,140	$ 44,374	Yes	Requests for proposals for specific jobs, time is directly attributable to capital projects
Inventory Adjustments	$ 20,867	$ 26,062	Yes	Costs related to materials used in capital projects
Depreciation	$ 3,407	$ 2,725	Yes	Depreciation costs relating to equipment used in Stores for assets purhcased for specific capital assets
Total	**$ 170,766**	**$ 145,215**		
Fleet:				
Repairs	$ 87,903	$ 88,513	Yes	Repairs cost for vehicles used in the construction of capital assets
Fuel	$ 29,100	$ 43,262	Yes	Fuel costs for using vehicles use for constructing capital assets
Depreciation	$ 111,550	$ 121,250	Yes	Depreciation costs relating to fleet used for constructing capital assets
Insurance	$ 10,573	$ 10,864	Yes	Insurance costs of fleet vehicles used for constructing capital assets
Total	**$ 239,126**	**$ 263,889**		
Payroll Burden:				
Benefits	$ 404,215	$ 417,430	Yes	Employee benefits considered part of employees' compensation are capitalized as directly attributable costs
Vacation and Stat Pay	$ 184,758	$ 212,008	Yes	Employee vacation and statutory pay considered employees' compensation are capitalized as directly attributable costs
Miscellaneous	$ 14,704	$ 15,684	Yes	Employee safety clothing, safety boots, service recognition, employee events considered compensation, therefore capitalized
Total	**$ 603,677**	**$ 645,122**		

f) Please identify the overall level of increase (decrease) in OM&A expense in the test year in relation to a decrease (increase) in capitalized overhead. Please provide a variance analysis for this increase in OM&A expense for the test year in respect to each of the bridge year and historical years.

Response:

The overall increase in OM&A is the same as the decrease in capitalized overhead, $616,555. The table below, also found in Exhibit 4, Tab 4, Schedule 1, provides the details of these changes.

Burdens		General & Administrative Labour	Labour Burden	IT Charges	Property Charge	Miscellaneous	Total
Engineering Burden		216,409		114,320	13,239		343,968
Stores Burden		7,113		20,520	103,790		131,423
Fleet Burden					36,300	9,000	45,300
Payroll Burden			95,864				95,864
Total		223,522	95,864	134,840	153,329	9,000	616,555
Burden amounts reallocated to OM&A	**2012 Test Year CGAAP**	**Amounts removed from Burdens aboved to be expensed in OM&A**					**2012 Test Year IFRS**
Operations	1,226,500	62,006					1,288,506
Maintenance	1,165,100	83,505					1,248,605
Billing & Collecting	1,228,062						1,228,062
Community Relations	37,000						37,000
Administration	1,544,400	78,011	95,864	134,840	153,329	9,000	2,015,444
Total	5,201,062	223,522	95,864	134,840	153,329	9,000	5,817,617

For the historical years 2008, 2009, 2010 the amount in OM&A was $0. When restating 2011 under IFRS the amount added to OM&A will be $597,066, based on budgeted expense. The increase from 2011 to 2012 of $19,489 or 3.26% is primarily the result of increased wages.

g) Please confirm that all borrowing costs that are directly attributable to the acquisition, construction, or production of PP&E costs are capitalized to PP&E and not expensed. If this is not the case, please explain.

Response:

IAS 23 requires borrowing costs to be expensed as they are incurred unless they relate to 'qualifying' assets, in which case they must be capitalized. A qualifying asset is one that requires a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in IAS 23. Based on discussion with KPMG and its external auditors, Norfolk determined for its purposes a period in excess of 6 months would be considered a substantial period of time. Norfolk does not have any projects planned in 2011 or 2012 that will extend past this time period and therefore Norfolk has not capitalized any interest within this application.

Please see Appendix 4 Borrowing Costs Board Staff IR 11g.

h) Where incurred debt is not acquired on an arm's length basis, are the actual borrowing costs used? Please explain.

Response:

Not applicable, see 11g above.

i) Please confirm that if the interest rate is greater than the Board's most recently published CWIP interest rates, Norfolk Power has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

Response:

Not applicable, see 11g above.

12. Ref: Exhibit 2/Tab 5/Sch 1

With regard to gains or losses on the Retirement in a Group of Like Assets/Asset Impairment Losses, page 19 of the July 2009 Report of the Board, Transition to IFRS stated:

"Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board."

Also at page 41 of the same report:

"Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates."

a) Please confirm that Norfolk Power has identified the gain or loss on the retirement of assets in a group of like assets. Please provide the treatment of the retirement for rate application purpose and disclose the amount. Please state the reasons if the gains/losses are not charged to depreciation expense.

Response:

Norfolk has identified that there are no gains or losses on the retirement of assets in the 2012 test year.

b) Please disclose any asset impairment loss recorded under IFRS which should be reclassified to PP&E. Please describe the nature of the losses, the amounts of the losses and the consideration whether and how such amounts are to be reflected in rates.

Response:

Not applicable.

13. Ref: Exhibit 2/Tab 5/Sch 1

With regard to Asset Retirement Obligations, page 40 of the July 2009 Report of the Board, Transition to IFRS stated:

"Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The Board will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement."

It appears that Norfolk Power did not present the accounting policy change on asset retirement obligations. As IFRS requires that asset retirement obligations include estimates of the cost of constructive obligations which was not required under CGAAP, and revaluation of those obligations during the lives of the assets. Please confirm whether or not Norfolk Power has any asset retirement obligations.

Response:

Norfolk does not have any asset retirement obligations at this time.

Please see Appendix 5 Asset Retirement Obligations Board Staff IR 13, 13c.

a) If yes, please identify and provide a detailed breakdown of the major asset components.

Response:

Not applicable.

b) If no, please provide a proposal for how the asset retirement obligations should be recovered in rates.

Response:

As Norfolk does not have any retirement obligations at this time, Norfolk does not have a proposal for how asset retirement obligations should be recovered in rates.

c) Has Norfolk Power identified the accounting change on asset retirement obligations? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

Response:

Please see Appendix 5 Asset Retirement Obligations Board Staff IR 13, 13c.

d) For the AROs identified, please provide the depreciation expenses and accretion expenses and how these expense are currently included in the rate application.

Response:

Not applicable.

14. Ref: Exhibit 2/Tab 5/Sch 1

With regard to borrowing costs, page 15 of the July 2009 Report of the Board, Transition to IFRS, stated:

"The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS."

IAS 16 Property, Plant and Equipment indicates that the cost of PP&E is comprised of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

Page 40 of the July 2009 Report of the Board, Transition to IFRS stated:

"The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates."

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

Response:

Please see response to Board Staff Interrogatory 11g and Appendix 4 Borrowing Costs Board Staff IR 11g.

b) Please confirm that borrowing costs that are directly attributable to the acquisition, construction, or production of qualifying PP&E are capitalized, with respect to incurred debt acquired on an arm's length basis. Please explain.

Response:

Not Applicable. Norfolk does not anticipate the construction of any assets which would qualify for the capitalization of interest.

c) Where incurred debt is not acquired on an arm's length basis, are the actual borrowing costs used? Please explain. Please confirm that if the interest rate is greater than the Board's most recently published CWIP interest rates, the Applicant has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

Response:

Not Applicable. Please see responses to Board Staff 14a and b as well as 11g.

d) Please confirm that that the amount of borrowing costs capitalized in a period in total does not exceed the actual borrowing costs incurred. If this is not the case, please explain.

Response:

Not Applicable. Norfolk does not anticipate any projects which would require capitalizing borrowing costs.

15. Ref: Exhibit 2/Tab 5/Sch 1

With regard to Intangible Assets, IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. As stated at page 40 of the July 2009 Report of the Board, Transition to IFRS:

"Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement."

It appears that Norfolk Power did not present the accounting policy change on asset reclassification from PP&E to intangible assets.

a) Has Norfolk Power identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

Response:

Norfolk has not created a policy change regarding the need to record computer software and land rights as intangible assets. However Norfolk is aware that this change in balance sheet presentation is required when the financial statements are prepared. As noted in the interrogatory, the Board has indicated that these assets continue to be included in rate base and the related amortization is to be included in depreciation expense for determining revenue requirement. Norfolk has included these amounts in its application as directed and therefore no further change is required for the purposes of the application. For financial statement purposes the amounts related to software and land rights will be removed from fixed assets, and reported separately as intangible assets.

b) For the assets identified in a), please propose the regulatory treatment in accordance with the Board report.

Response:

Norfolk proposes the net book value of the assets classified as software and land rights continue to be included in rate base and the associated depreciation be included in depreciation expense. Norfolk has prepared its application on this basis and believes this approach is consistent with the Board direction provided in the July 2009 Report of the Board as quoted in the interrogatory.

16. Ref: Exhibit 2/Tab 5/Sch3

Table 5.8 compares Rate Base under CGAAP and MIFRS for 2012. Please provide further detail on how the average net book value was derived.

Response:

The average net book value is based on the 2012 opening and closing net book value. Norfolk has reproduced Table 5.8 with additional columns to show the inclusion of Smart Meters and the exclusion of Stranded Meters. Accumulated Depreciation has also been adjusted accordingly.

	2011 Bridge GAAP	2012 Test GAAP O/B	2012 Test GAAP C/B		2011 Bridge IFRS	2012 Test IFRS O/B	2012 Test IFRS C/B
Gross Fixed Assets	79,147,237	79,147,237	84,994,791		52,667,450	52,667,450	59,274,191
Add Smart Meters		3,620,385				3,620,385	
Remove Stranded Assets		-2,180,831				-914,164	
Accumulated Depreciation	28,808,038	28,116,378	31,482,220		1,970,919	2,526,401	4,984,969
Net Book Value	50,339,199	52,470,413	53,512,571		50,696,531	52,847,270	54,289,222
Average Net Book Value			52,991,496				53,568,246
Working Capital Allowance (15%)			5,992,935				6,085,418
Rate Base			58,984,431				59,653,664

17. Ref: Exhibit 4/Tab 4/Sch 2/p. 1&2

Board policy articulates that LDCs shall use the Board sponsored Kinectrics study or sponsor their own study to justify changes in useful lives. The typical useful lives (TUL) from the Kinectrics report is the recommended reference point. The Board will no longer prescribe service lives for PP&E. *As the Board said in* its Report of the Board Transition to International Financial Reporting Standards

("IFRS") July 28, 2009 EB-2008-0408 on page 21

"The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization."

And also in the Letter of the Board Depreciation Study for Use by Electricity Distributors, July 8, 2010

"The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board."

a) What changes has Norfolk Power made to its Depreciation Policy due to MIFRS (e.g. pooling of assets is not permitted under IFRS).

Response:

Significant components of PP&E will be separately accounted for under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense, have been studied with the assistance of KPMG. Norfolk has submitted a policy document concerning the significant components and their estimated useful lives. Please see Appendix 6 Depreciation – Amortization Policy Board Staff IR 19b.

Each year end, Norfolk Power will reassess each significant component and its estimated useful lives for the purpose of computing depreciation expense moving forward.

b) Please provide a list of detailed asset service lives and identify all exceptions from the Typical Useful Lives ("TUL") in the Kinectrics Report and provide detailed justification for using service lives that are different from the TULs in the Kinectrics Report.

Response:

Please see table below.

USoA/Sub Account	Description	IFRS	Kinectrics Min, Typ, Max
1805	Land - Distribution Plant	N/A	N/A
1806	Land Rights - Distribution Plant	N/A	N/A
1808	Transformer Station Building	50	50-75
1815	Station DC System	20	10, 20, 30
1815	Power Transformers	45	30, 45, 60
1815	Station Switchgear	40	30, 40, 60
1820	Distribution Station Equipment	20	10, 20, 30
1830	POLES - Wood/Concrete	45	Wood 35, 45, 75, Concrete 50, 60, 80
1835	O/H Conductors & Devices - OH Conductors Primary	60	50, 60, 75
1840	U/G Conduit - Ducts	50	30, 50, 85
1845	U/G Conductors & Devices UG Primary Cables	30	25, 30, 35
1850	Pad-Mounted Transformers	35	25, 40, 45
1850	OH Transformers & Voltage Regulators	40	30, 40, 60
1855	Services - Secondary Cables - Direct Buried/Other (inc. OH)	40	20, 35, 40
1860	Other Meters, PT's & CT's	30	25-35
1860	Smart Meters	10	5-15
1905	Land - General Plant	N/A	N/A
1908	Service Centre Building	50	50-75
1910	Lease Improvements - Hunt Street	10	Lease Dependent
1915	Office Equipment	10	5-15
1920	Computer Hardware	4	3-5
1925	Smart Meter - Software	5	2-5
1925	Computer Software	5	2-5
1930	Transportation Equipment - Passenger Vehicles/Small Trucks	7	5-10
1930	Transportation Equipment - Bucket Trucks	15	5-15
1935	Stores Equipment	10	5-10
1940	Tools & Garage Equipment	10	5-10
1945	Measurement & Testing Equipment	5	5-10
1955	Communications Equipment	5	2-10
1960	Miscellaneous Equipment	5	5-10
1980	SCADA	20	10, 20, 30
1995	Contributed Capital	25	Asset Dependent
2005	Property Under Capital Lease	10	Lease Dependent

Poles:

Norfolk Power's poles are a mixture of wood and concrete with the majority of the poles in the system being wood. Hence, Norfolk has adopted the TUL for wood poles (45 years) as the IFRS amortization period for this component.

Pad Mounted Transformers:

Norfolk has no network transformers, only pad-mounted and a few submersible transformers. Since the underground system is not typically overloaded, there have been limited switching issues or cable faults. Norfolk has selected a Typical Useful Life (35 years) as the average of the Min and Max useful lives as set out in the Kinectrics Report ((25 + 45)/2 = 35).

Services – Secondary Cables – Direct Buried/Other (inc. OH):

Norfolk has no PILC cable but has both direct and in duct cabling, the majority of which is direct buried. Norfolk has not had significant problems with direct buried lines. In duct, cable has only been used since 2000 and there is limited data on the typical useful life. Secondary overhead and underground cables estimated to last the same amount of time. There have been few faults on underground cable which suggests that the typical useful life should be greater than what the Kinectrics report identified. Norfolk has selected 40 years for the IFRS amortization period for this component.

c) For the bridge and test years, please provide a breakdown of the components of the underlying PP&E assets (i.e. pool assets is not permitted), including gross capital cost and accumulated depreciation values, revised useful lives, and the calculation of the depreciation expense based on revised service lives.

Response:

Please refer to Norfolk's response to Energy Probe Interrogatory #25.

d) Please confirm that significant parts or components of each item of PP&E are being depreciated separately.

Response:

Norfolk confirms that significant parts or components of each item of PP&E are being depreciated separately.

18. Ref: Exhibit 4/Tab 4/Sch 2

Table 4.2 presents the IFRS Amortization Expense USoA account for both 2011 and 2012 but does not provide details of how this was calculated. Please provide information based on Appendix 2M for 2011 MIFRS.

Response:

Norfolk would like to note that its IFRS amortization calculations involve a complex system of equations which are not easily replicated in a word document.

Norfolk has provided tables similar to the depreciation calculation tables found in the Chapter 2 Filing Requirements "Appendix B" excel file. Norfolk has used an "Average Estimated Remaining Useful Life" as the IFRS amortization period for the purpose of showing calculations in table format. As this method is not "perfect", there are several anomalies which have been explained where applicable. Please find those tables below.

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Appendix 2-M
Depreciation and Amortization Expense

Year: 2011 **MIFRS**

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Average Remaining Life of Opening Balance (i)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation expense on opening (j)=(a)/(i)	Depreciation Expense on Additions (h)=(d)/(f)/2	Total Depreciation Expense (MIFRS) (k)=(j)+(h)	Depreciation Expense Per Continuity Schedule (Table 5.1 of Exh 2/Tab 5/ Schedule 1)	Variance (Immaterial)
1730	Transmission Plant	$ 2,193.75		$ 2,193.75	$ -	$ 2,193.75	22.00	25.00	4.0%	$ 99.72	$ -	$ 99.72	$ 99.72	$ 99.72
1805	Land	$ 391,259.39		$ 391,259.39	$ -	$ 391,259.39	-	-						
1806	Land Rights	$ 302,784.48		$ 302,784.48	$ 1,000.00	$ 303,284.48	-	-						
1808	Transformer Station Building	$ 1,439,503.08		$ 1,439,503.08	$ -	$ 1,439,503.08	43.47	50.00	2.0%	$ 33,114.86	$ -	$ 33,114.86	$ 33,111.95	-$ 2.91
1815	Power Transformers	$ 5,136,797.68		$ 5,136,797.68	$ -	$ 5,136,797.68	41.36	45.00	2.2%	$ 124,197.24	$ -	$ 124,197.24	$ 124,188.54	-$ 8.69
1815	Station Switchgear	$ 2,708,365.71		$ 2,708,365.71	$ -	$ 2,708,365.71	36.34	40.00	2.5%	$ 74,528.50	$ -	$ 74,528.50	$ 74,521.60	-$ 6.90
1815	Station DC System	$ 540,639.08		$ 540,639.08	$ -	$ 540,639.08	16.13	20.00	5.0%	$ 33,517.61	$ -	$ 33,517.61	$ 33,519.66	$ 2.04
1820	Distribution Station Equipment	$ 2,404,513.58		$ 2,404,513.58	$ 65,131.00	$ 2,437,079.08	15.24	20.00	5.0%	$ 157,802.37	$ 3,256.55	$ 161,058.92	$ 161,058.80	-$ 0.12
1830	OH Poles (Fully Dressed)	$ 13,659,081.90		$ 13,659,081.90	$ 1,038,945.00	$ 14,178,554.40	35.60	45.00	2.2%	$ 383,682.08	$ 11,543.83	$ 395,225.91	$ 395,240.46	$ 14.55
1835	OH Line Switch	$ 1,942,630.98		$ 1,942,630.98	$ 165,551.27	$ 2,025,406.61	33.10	40.00	2.5%	$ 58,689.76	$ 2,069.39	$ 60,759.15	$ 60,764.09	$ 4.94
1835	OH Conductors - Primary	$ 6,718,139.59		$ 6,718,139.59	$ 572,520.73	$ 7,004,399.96	53.22	60.00	1.7%	$ 126,233.36	$ 4,771.01	$ 131,004.37	$ 131,008.57	$ 4.20
1840	UG Conduits	$ 2,503,558.32		$ 2,503,558.32	$ 191,050.00	$ 2,599,083.32	42.94	50.00	2.0%	$ 58,303.64	$ 1,910.50	$ 60,214.14	$ 60,211.21	-$ 2.93
1845	UG Primary Cables	$ 4,923,360.84		$ 4,923,360.84	$ 336,943.00	$ 5,091,832.34	23.06	30.00	3.3%	$ 213,502.20	$ 5,615.72	$ 219,117.92	$ 219,158.00	$ 40.07
18501	OH Transfomers & Voltage Regulators	$ 2,763,736.56		$ 2,763,736.56	$ 784,127.00	$ 3,155,800.06	33.70	40.00	2.5%	$ 82,009.99	$ 9,801.59	$ 91,811.57	$ 91,802.80	-$ 8.77
18502	Pad-Mounted Transfomers	$ 2,508,140.89		$ 2,508,140.89	$ -	$ 2,508,140.89	30.22	35.00	2.9%	$ 82,996.06	$ -	$ 82,996.06	$ 83,000.81	$ 4.75
1855	Secondary Cables (UG & OH)	$ 2,258,010.15		$ 2,258,010.15	$ 232,828.00	$ 2,374,424.15	35.25	40.00	2.5%	$ 64,057.03	$ 2,910.35	$ 66,967.38	$ 66,958.42	-$ 8.95
1860	Residential Meters (Stranded)	$ 914,164.13		$ 914,164.13	$ -	$ 914,164.13	17.09	25.00	4.0%	$ 53,491.17	$ -	$ 53,491.17	$ 53,492.72	$ 1.55
1860	Wholesale/Interval Meters	$ 307,216.17		$ 307,216.17	$ 22,140.46	$ 318,286.40	17.09	25.00	4.0%	$ 17,976.37	$ 442.81	$ 18,419.18	$ 18,419.70	$ 0.52
1860	Other meters (CTs &PTs)	$ 560,616.05		$ 560,616.05	$ 40,385.54	$ 580,808.82	22.32	30.00	3.3%	$ 25,117.21	$ 673.09	$ 25,790.30	$ 25,794.15	$ 3.85
1860	Smart Meters	$ -		$ -		$ -		15.00	6.7%			$ -	$ -	$ -
1905	Land	$ 243,635.89		$ 243,635.89	$ -	$ 243,635.89		-	0.0%			$ -	$ -	$ -
19801	Building - Service Centre	$ 1,461,862.58		$ 1,461,862.58	$ 10,000.00	$ 1,466,862.58	14.47	50.00	2.0%	$ 101,027.13	$ 100.00	$ 101,127.13	$ 101,096.77	-$ 30.36
19802	Building - Pond Street Storage	$ 4,683.16		$ 4,683.16	$ -	$ 4,683.16	17.00	25.00	4.0%	$ 275.48	$ -	$ 275.48	$ 275.48	$ -
1910	Leasehold Improvements - Hunt St	$ 2,313.94		$ 2,313.94	$ -	$ 2,313.94	3.54	10.00	10.0%	$ 653.66	$ -	$ 653.66	$ 653.98	$ 0.32
1915	Office Equipment	$ 58,409.10		$ 58,409.10	$ 15,000.00	$ 65,909.10	4.15	10.00	10.0%	$ 14,074.48	$ 750.00	$ 14,824.48	$ 15,567.59	$ 743.11
1920	Computer Hardware	$ 159,156.30		$ 159,156.30	$ 30,000.00	$ 174,156.30	2.68	4.00	25.0%	$ 59,386.68	$ 3,750.00	$ 63,136.68	$ 63,094.60	-$ 42.08
1925	Computer Software	$ 122,771.25		$ 122,771.25	$ 27,000.00	$ 136,271.25	3.52	5.00	20.0%	$ 34,878.20	$ 2,700.00	$ 37,578.20	$ 37,574.00	-$ 4.20
1925-1	Computer Software - Smart Meters	$ -		$ -		$ -		5.00	20.0%		$ -	$ -	$ -	$ -
1930	Vehicles - Bucket Trucks	$ 392,326.64		$ 392,326.64	$ 440,000.00	$ 612,326.64	8.53	15.00	6.7%	$ 45,993.74	$ 14,666.67	$ 60,660.41	$ 60,681.49	$ 21.07
1930	Vehicles - Other	$ 83,780.54		$ 83,780.54	$ -	$ 83,780.54	3.85	7.00	14.3%	$ 21,761.18	$ -	$ 21,761.18	$ 21,769.77	$ 8.59
1935	Stores Equipment	$ 14,447.41		$ 14,447.41	$ -	$ 14,447.41	3.62	10.00	10.0%	$ 3,991.00	$ -	$ 3,991.00	$ 3,990.39	-$ 0.61
19400	Tools & Garage Equipment	$ 118,167.29		$ 118,167.29	$ 35,000.00	$ 135,667.29	4.17	10.00	10.0%	$ 28,337.48	$ 1,750.00	$ 30,087.48	$ 30,090.13	$ 2.65
19401	Recloser Shop Tools & Equipment	$ 15,251.71		$ 15,251.71	$ -	$ 15,251.71	7.00	10.00	10.0%	$ 2,178.82	$ -	$ 2,178.82	$ 2,178.82	$ -
1945	Measurement & Testing Equipment	$ 70,554.12	$ 42,514.43	$ 28,039.69	$ -	$ 28,039.69	5.53	5.00	20.0%	$ 12,758.43	$ -	$ 12,758.43	$ 12,761.93	$ 3.50
19550	Communication Equipment	$ 51,871.94	$ 13,132.76	$ 38,739.18	$ 8,000.00	$ 42,739.18	2.25	5.00	20.0%	$ 23,054.20	$ 800.00	$ 23,854.20	$ 23,865.70	$ 11.50
1980/19801	Scada	$ 844,439.20		$ 844,439.20	$ 212,761.00	$ 950,819.70	16.00	20.00	5.0%	$ 52,777.45	$ 5,319.03	$ 58,096.48	$ 58,080.78	-$ 15.70
1960	Miscellaneous Equipment	$ 299,191.96	$ 33,856.92	$ 265,335.04	$ -	$ 265,335.04	3.00	5.00	20.0%	$ 99,730.65	$ -	$ 99,730.65	$ 99,699.41	-$ 31.24
2005	Property under Capital Assets	$ 4,015.44		$ 4,015.44	$ -	$ 4,015.44	4.00	10.00	10.0%	$ 1,003.86	$ -	$ 1,003.86	$ 1,003.86	$ -
1995	Contributed Capital	-$ 6,541,681.20		-$ 6,541,681.20	-$ 861,340.00	-$ 6,972,351.20		various				-$ 193,817.32	-$ 193,817.32	
	Total	**$ 49,389,909.59**	**$ 89,504.11**	**$ 49,300,405.48**	**$ 3,367,043.00**	**$ 50,983,926.98**				**$ 2,091,201.59**	**$ 72,830.53**	**$ 1,970,214.79**	**$ 1,970,918.56**	**$ 803.48**

Subtotal Depreciation Expense (Before Allocations) in Table 5.1 $ 1,970,919.00

DIFFERENCE $ -

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Appendix 2-M
Depreciation and Amortization Expense

Year: 2012 MIFRS

Account	Description	Opening Balance (a)	Less Fully Depreciated or Other Adjustments (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (New Additions Only) (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (MIFRS) (h) =2011 depn +(d)/(f)	Depreciation Expense Per Continuity Schedule (Table 5.2, Exh 2/Tab 5/Sch 1)	Variance	Note to Explain Variances If Applicable
1730	Transmission Plant	$ 2,193.75		$ 2,193.75	$ -	$ 2,193.75	25.00	4.0%	$ 99.72	$ 99.72	$ -	
1805	Land	$ 391,259.39		$ 391,259.39	$ -	$ 391,259.39	-			$ -	$ -	
1806	Land Rights	$ 303,784.48		$ 303,784.48	$ -	$ 303,784.48	-			$ -	$ -	
1808	Transformer Station Building	$ 1,439,503.08		$ 1,439,503.08	$ -	$ 1,439,503.08	50.00	2.0%	$ 33,114.86	$ 33,111.95	-$ 2.91	
1815	Power Transformers	$ 5,136,797.68		$ 5,136,797.68	$ -	$ 5,136,797.68	45.00	2.2%	$ 124,197.24	$ 124,188.54	-$ 8.69	
1815	Station Switchgear	$ 2,708,365.71		$ 2,708,365.71	$ -	$ 2,708,365.71	40.00	2.5%	$ 74,528.50	$ 74,521.60	-$ 6.90	
1815	Station DC System	$ 540,639.08		$ 540,639.08	$ -	$ 540,639.08	20.00	5.0%	$ 33,517.61	$ 33,519.66	$ 2.04	
1820	Distribution Station Equipment	$ 2,469,644.58		$ 2,469,644.58	$ 245,564.00	$ 2,592,426.58	20.00	5.0%	$ 167,198.02	$ 167,197.90	-$ 0.12	
1830	OH Poles (Fully Dressed)	$ 14,698,026.90		$ 14,698,026.90	$ 1,306,399.00	$ 15,351,226.40	45.00	2.2%	$ 421,285.29	$ 421,299.84	$ 14.55	
1835	OH Line Switch	$ 2,108,182.24		$ 2,108,182.24	$ 185,270.80	$ 2,200,817.64	40.00	2.5%	$ 65,144.42	$ 63,079.98	-$ 2,064.45	1
1835	OH Conductors - Primary	$ 7,290,660.32		$ 7,290,660.32	$ 640,716.20	$ 7,611,018.42	60.00	1.7%	$ 141,114.68	$ 136,347.87	-$ 4,766.80	2
1840	UG Conduits	$ 2,694,608.32		$ 2,694,608.32	$ 89,296.00	$ 2,739,256.32	50.00	2.0%	$ 63,017.60	$ 63,014.67	-$ 2.93	
1845	UG Primary Cables	$ 5,260,303.84		$ 5,260,303.84	$ 181,271.00	$ 5,350,939.34	30.00	3.3%	$ 227,754.82	$ 227,794.90	$ 40.07	
18501	OH Transfomers & Voltage Regulators	$ 3,547,863.56		$ 3,547,863.56	$ 850,097.00	$ 3,972,912.06	40.00	2.5%	$ 112,239.37	$ 112,230.60	-$ 8.77	
18502	Pad-Mounted Transfomers	$ 2,508,140.89		$ 2,508,140.89	$ -	$ 2,508,140.89	35.00	2.9%	$ 82,996.06	$ 83,000.81	$ 4.75	
1855	Secondary Cables (UG & OH)	$ 2,490,838.15		$ 2,490,838.15	$ 334,860.00	$ 2,658,268.15	40.00	2.5%	$ 74,063.48	$ 74,054.52	-$ 8.95	
1860	Residential Meters (Stranded)	$ 914,164.13	$ 914,164.13	$ -	$ -	$ -	25.00	4.0%	$ -		$ -	
1860	Wholesale/Interval Meters	$ 329,356.63		$ 329,356.63	$ 110,036.58	$ 384,374.92	25.00	4.0%	$ 21,062.72	$ 21,063.24	$ 0.52	
1860	Other meters (CTs &PTs)	$ 601,001.60		$ 601,001.60	$ 200,713.43	$ 701,358.31	30.00	3.3%	$ 29,808.62	$ 29,812.46	$ 3.85	
1860	Smart Meters	$ 2,734,702.85		$ 2,734,702.85		$ 2,734,702.85	8.51	11.8%	$ 321,351.69	$ 321,401.00	$ 49.31	3
1905	General Plant Land	$ 243,635.89		$ 243,635.89	$ -	$ 243,635.89	-	0.0%	$ -	$ -	$ -	
19801	Building - Service Centre	$ 1,471,862.58		$ 1,471,862.58	$ -	$ 1,471,862.58	14.47	6.9%	$ 101,227.13	$ 101,196.77	-$ 30.36	
19802	Building - Pond Street Storage	$ 4,683.16		$ 4,683.16	$ -	$ 4,683.16	25.00	4.0%	$ 275.48	$ 275.48	$ -	
1910	Leasehold Improvements - Hunt St	$ 2,313.94		$ 2,313.94	$ -	$ 2,313.94	10.00	10.0%	$ 653.66	$ 653.98	$ 0.32	
1915	Office Equipment	$ 73,409.10		$ 73,409.10	$ 15,500.00	$ 81,159.10	10.00	10.0%	$ 16,349.48	$ 13,789.65	-$ 2,559.83	4
1920	Computer Hardware	$ 189,156.30		$ 189,156.30	$ 40,000.00	$ 209,156.30	4.00	25.0%	$ 71,886.68	$ 93,720.48	$ 21,833.80	5
1925	Computer Software	$ 149,771.25		$ 149,771.25	$ 142,500.00	$ 221,021.25	5.00	20.0%	$ 54,528.20	$ 47,211.48	-$ 7,316.72	6
1925-1	Computer Software - Smart Meters	$ 287,612.28		$ 287,612.28		$ 287,612.28	2.83	35.3%	$ 101,629.78	$ 101,593.49	-$ 36.29	7
1930	Vehicles - Bucket Trucks	$ 832,326.64		$ 832,326.64	$ 40,000.00	$ 852,326.64	15.00	6.7%	$ 76,660.41	$ 76,681.49	$ 21.07	
1930	Vehicles - Other	$ 83,780.54		$ 83,780.54	$ -	$ 83,780.54	7.00	14.3%	$ 21,761.18	$ 21,769.77	$ 8.59	
1935	Stores Equipment	$ 14,447.41		$ 14,447.41	$ -	$ 14,447.41	10.00	10.0%	$ 3,991.00	$ 3,107.49	-$ 883.51	8
19400	Tools & Garage Equipment	$ 153,167.29		$ 153,167.29	$ 28,000.00	$ 167,167.29	10.00	10.0%	$ 33,237.48	$ 28,780.01	-$ 4,457.47	9
19401	Recloser Shop Tools & Equipment	$ 15,251.71		$ 15,251.71	$ -	$ 15,251.71	10.00	10.0%	$ 2,178.82	$ 2,178.82	$ -	
1945	Measurement & Testing Equipment	$ 28,039.69		$ 28,039.69	$ -	$ 28,039.69	5.00	20.0%	$ 12,758.43	$ 9,771.76	-$ 2,986.67	10
19550	Communication Equipment	$ 46,739.18		$ 46,739.18	$ 53,000.00	$ 73,239.18	5.00	20.0%	$ 29,954.20	$ 22,088.50	-$ 7,865.70	11
1980/19801	Scada	$ 1,057,200.20		$ 1,057,200.20	$ 89,296.00	$ 1,101,848.20	20.00	5.0%	$ 65,647.90	$ 65,632.20	-$ 15.70	
1960	Miscellaneous Equipment	$ 265,335.04		$ 265,335.04	$ -	$ 265,335.04	5.00	20.0%	$ 99,730.65	$ 88,879.36	-$ 10,851.29	12
2005	Property under Capital Assets	$ 4,015.44		$ 4,015.44	$ -	$ 4,015.44	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -	
1995	Contributed Capital	-$ 7,403,021.20		-$ 7,403,021.20	-$ 652,000.00	-$ 7,729,021.20	various		-$ 205,507.14	-$ 205,507.14	$ -	
	Total	**$ 55,689,763.61**	**$ 914,164.13**	**$ 54,775,599.49**	**$ 3,900,520.01**	**$ 56,725,859.49**			**$ 2,480,461.87**	**$ 2,458,566.69**	**-$ 21,895.18**	

Subtotal Depreciation Expense (Before Allocations) in Table 5.2 **$ 2,458,567.00**
DIFFERENCE **$ -**

Notes to Explain Variances:

1 2012 depreciation for 2011 additions was calculated as 1/2 the depreciation amount in error
2 2012 depreciation for 2011 additions was calculated as 1/2 the depreciation amount in error
3 average remaining useful life used since smart meters have been purchased over several years - actual useful life is 15 years (for new additions)
4 2002 additions have become fully depreciated so no depreciation is taken in 2012
5 2012 depreciation calculation error
6 depreciation on 2011 additions was calculated as 0 in error, depreciation should have been$ 5,400
7 average remaining useful life used since smart meter software has been purchased over several years - actual useful life is 5 years (for new additions)
8 2002 additions have become fully depreciated so no depreciation is taken in 2012
9 2002 additions have become fully depreciated so no depreciation is taken in 2012
10 2007 additions have become fully depreciated so no depreciation is taken in 2012
11 2007 additions have become fully depreciated so no depreciation is taken in 2012
12 2007 additions have become fully depreciated so no depreciation is taken in 2012

19. Ref: Exhibit 4/Tab 4/Sch 2

a) Please provide a summary of the changes to Norfolk Power's accounting policies (including capitalization) made since Norfolk Power's last cost of service rate filing.

Response:

In 2010 Norfolk changed to the half year rule for the amortization of new assets. This change reflected the 2008 cost of service application in which rates were based on the half year rule.

Other changes to accounting policies are related to IFRS and are fully described in the interrogatories above and in the following Appendices:

Appendix 3 Conclusion Document IAS 16 PPE Burdens Board Staff IR 11c
Appendix 4 Borrowing Costs Board Staff IR 11g
Appendix 5 Asset Retirement Obligations Board Staff IR 13, 13c
Appendix 6 Depreciation – Amortization Policy Board Staff IR 19b

b) Please provide a copy of Norfolk Power's depreciation/amortization policy or a summary of the depreciation practices followed and used in preparation of this application.

Response:

Please see Appendix 6 Depreciation – Amortization Policy Board Staff IR 19b.

Capital Expenditures

20. Ref: Exhibit 2/Tab 3/Sch 2/p.41

Norfolk Power provides a summary of the 2011 projects related to the GEA. Please provide a current year-to-date update to these GEA related investments. Will all of these projects come into service by the end of 2011? If not, will the GEA related plans for 2012 be affected?

Response:

Please see the table below regarding the **2011 year to date** GEA related investments.

Generator Capacity	**2011 GEA Plan Estimated Connections**	**Connections** (as of Nov. 18, 2011)	**Costs**	**Capital Contributions**	**Capacity Connected (kW)**
≤10kW	50	22	$27,000*	$28,715	220
>10kW to 250kW	6	1	$41,440	$76,050	100
>250kW	2	0	$155,358	$228,175	0

* Excludes transformer costs

It is expected that some of the FIT projects originally slated for connection in 2011 will now occur in 2012. Carryover of these projects should not affect Norfolk Power's ability to proceed with planned 2012 projects.

21. Ref: Exhibit 2/Tab 3/Sch 2/p. 49 & p. 61

Norfolk Power's capital budget for 2011 and 2012 includes $303,000 for Subdivision Development in each year. For 2011 the evidence indicates that the "specifics are unknown" and for 2012 it indicates that "approximately 180 new lots are anticipated". Can Norfolk Power provide additional analysis and information on how this budget was developed for 2011 and 2012 and how much of this cost is to be recovered from capital contributions?

Response:

For 2012, Norfolk Power has used a "bottom up" estimate to calculate subdivision costs based on a recent historical per lot basis of $1,683/lot. Due to fluctuating economic conditions and a change in senior staff, Norfolk Power cannot provide additional analysis for the 2011 and 2012 figures.

Year	2008	2009	2010	2011	2012
Total Costs	$104,883	$358,166	$276,359	$303,000*	$303,000*
Capital Contributions	$70,000	$143,000	$234,000	$258,000*	$258,000*

* Estimated

22. Ref: Exhibit 2/Tab 3/Sch 2

Norfolk Power's capital contributions fluctuate significantly from 2008 to 2012. How does Norfolk Power forecast capital contributions for 2011 and 2012 and how does this forecast relate to the forecast customer additions in the Load Forecast?

Response:

The 2012 contributed capital is based on the historical contributed capital as a percentage of the expenses it was contributed for, namely conduit, UG Conductor, Transformers and Services. In reviewing actual contributions in the past, contributions averaged 40% of these expenses. In 2012 40% of the budgeted amounts expenses was used to estimate contributed capital. The table below summarizes the calculations involved.

	2008 Actual	2009 Actual	2010 Actual	Total 2008 2009 2010		2011 Bridge	2012 Test
Contributed Capital	331,461	531,414	819,501	1,682,376		861,000	652,000
Expenses:							
Conduit	54,312	312,485	160,330	527,127		220,000	100,000
UG Conductor	176,668	515,163	255,331	947,162		388,000	203,000
Transformers	741,072	421,377	744,522	1,906,971		865,000	952,000
Services	285,341	277,123	271,076	833,540		266,000	375,000
Total Expenses	1,257,393	1,526,148	1,431,259	4,214,800		1,739,000	1,630,000
Contributions as a Percentage of Expense	26%	35%	57%	40%		50%	40%

In regards to the $819,501 of contributed capital in 2010 it is noted that $208,079 of this amount was for unusual projects that are not budgeted for in 2012. In addition the $861,000 of contributed capital in 2011 includes $351,340 for the connection of a RESOP generator (Identified as project 13 under the 2011 capital projects), which is not budgeted to reoccur in 2012.

Contributions are not just for new customer additions and therefore the forecast does not tie directly to the Load Forecast. In addition to new customers, contributions are also received for service upgrades and subdivision development.

23. Ref: Exhibit 2/Tab 3/Sch 2/p. 64, p. 53 & p. 37

Norfolk Power has budgeted $40,000 for the purchase of a new pick-up truck in 2012, in addition to $440,000 for various vehicles in 2011 and $76,000 in 2010. This follows quite low vehicle expenditures in 2008 and 2009.

a) Why were vehicle expenditures so low in 2008 and 2009?

Response:

In 2008 and 2009, Norfolk Power determined that the vehicles in use did not need replacement at that time and as a result no significant expenditures were made.

b) Please provide a summary of the current Norfolk Power vehicle fleet, including vehicle vintage, value and condition.

Response:

Condition is based on overall assessment of the vehicle considering factors such as mechanical condition, body and frame condition, repair costs and frequency, and age.

Please see table below showing Norfolk Power's fleet:

Make	Vehicle Unit Number & Description	Year	Condition	Net Book Value
FORD	Unit # 2 - Pickup - 1999 Ford	1999	fair	$ -
	(UNIT 2 - WEIGHT RE-REGISTERED Mar 2007)			
DODGE	Unit # 7 - Pickup - 2002 Dodge 3/4 ton	2002	fair	$ -
CHEV	Unit # 8 - Pickup - 2007 GMC Sierra Extended Cab	2007	excellent	$ 2,515
CHEV	Unit # 9 - Pickup - 2007 GMC Sierra Extended Cab	2007	Excellent	$ 2,515
CHEV	Unit # 10 - Pickup - 2003 Chev Sierra	2003	Good	$ -
GMC	Unit # 11 - 2003 GMC Sierra SL 4x4 Ext Cab	2003	Good	$ -
CHEV	Unit # 15 - 2005 Chev Silverado 4x4 Ext Cab	2005	Good	$ -
CHEV	Unit # 16 - 2005 Chev Silverado 4x4 Ext Cab	2005	Good	$ -
CHEV	Unit # 17 - 2006 Chev Sivlerado 4x4 Ext Cab	2006	Good	$ -
GMC	Unit # 18 - 2011 GMC Sierra 4x4 Ext Cab	2011	Excellent	$ 20,749
CHEV	Unit # 19 - 2011 Chev Silverado 4x4 Crew Cab	2011	Excellent	$ 28,606
CHEV	Unit # 22 - Meter Van - 2002 Ford	2002	Fair	$ -
CHEV	Unit # 23 - Van - Chev Venture Cargo 2003	2003	Fair	$ -
CHEV	Unit # 24 - Van - 2004 Chev Savannah Cargo	2004	Fair	$ -
CHEV	Unit # 28 - Car - Chev Cobalt Sedan	2006	Fair	$ -
INTERNATIONAL	Unit #32 - Hiab Crane Work Platform - 2001 International	2001	good	$ 19,930
FORD	Unit #42 - Radial Boom Digger Derrick- 1992 Ford	1992	poor	$ -

Make	Vehicle Unit Number & Description	Year	Condition	Net Book Value
INTERNATIONAL	Unit # 43 - Radial Boom Digger Derrick 2006 International	2006	Good	$ 89,758
FREIGHTLINER	Unit # 53 - Single Bucket Aerial Device - 2002 Freightliner	2002	Fair	$ -
FREIGHTLINER	Unit # 54 - Single Bucket Aerial Device - 2004 Freightliner	2004	good	$ 11,482
FREIGHTLINER	Unit # 55 - Single Bucket Aerial Device - 2011 Freightliner	2011	Excellent	$272,126
FREIGHTLINER	Unit # 60 - Double Bucket Aerial Device- 1997 Freightliner	1997	Poor	$ -
FREIGHTLINER	Unit # 63 - Double Bucket Aerial Device - 2004 Freigthliner	2004	Good	$ 16,940
TOYOTA	Unit # 70 - Fork Lift (model 42-6FGU25)		Good	$ 7,500
RAYMOND	Unit # 71 - Reach Truck (model 20R30TT)	1981	Good	$ -
SAUBER	Unit # 74 - Substation Recovery Trailer	2011	Excellent	$ 50,154
JC Cat	Unit # 75 - J.C Cat - holds generator	2008	Excellent	$ 33,881
THRUWAY	Unit # 76 - Thruway Trailer - holds mobile substation	2008	Excellent	$ 57,375
J.C. TRAILERS	Unit # 77 - J.C Pole Trailer	2008	Excellent	$ 12,029
MOFFAT	Unit # 78 - Tandem Dump Trailer 2005	2005	Good	$ 4,922
TJWL	Unit # 80 - T.J. Welding Pole Trailer	1990	Good	$ -
Brindle	Unit # 81 - Brindle Reel Trailer	2009	Excellent	$ 7,109
UTIL	Unit # 83 - Equipment Trailer	1999	Fair	$ -
TIMBERLAND	Unit # 86 - Tension Stringing Machine	2003	Excellent	$ -
HOME	Unit # 87 - Spill Response Trailer	2003	Excellent	$ -
JCTR	Unit # 88 - J.C. Reel Trailer	2003	Good	$ -

c) Please provide Norfolk Power's vehicle replacement policy.

Response:

At present, Norfolk Power does not have a formal vehicle replacement policy. Vehicles are used until issues arise with the mechanical operation, body and frame condition, or repair costs/frequency.

d) Please provide a forecast of Norfolk Power's proposed vehicle replacements in 2013, 2014 and 2015, including reasons/rationale and please state if Norfolk Power intends to include Electric Vehicles as part of its vehicle replacement strategy.

Response:

Norfolk has summarized its projected vehicle replacements in the table below. Each year Norfolk assesses the vehicle fleet for the need for replacement. Norfolk assesses the vehicles each year at budget time to determine if projected replacement is actually warranted.

Replacement year	Type	Repair Costs 2007 - 2011	Estimated Market value	Condition	Km	Age at replacement
2012	van	$7,673	$3,500	rust/no frame issues	120,010	10 years
2013	RBD	$100,097	$12,000	lot of rust/frame issues	118,245	21 years
2013	pickup	$7,061	$6,000	some rust	109,411	11 years
2014	van	$8,920	$4,000	some rust	114,962	10 years
2014	Single Bucket	$92,007	$40,000	rust/no frame issues	234,135	12 years
2014	Pickup	$6,290	$7,000	rust/no frame issues	136,647	10 years
2015	Van	$5,080	$4,000	some rust	76,586	12 years

Norfolk Power is not planning to use electric vehicles at this time.

24. Ref: Exhibit 2/Tab 3/Sch 2

Norfolk Power's investments in SCADA grew from $9,995 and $4,572 in 2008 and 2009 respectively to $550,000 in 2010, $245,000 in 2011 and $100,000 in 2012. Please provide Norfolk Power's rationale for this significant increase in spending on SCADA over the past few years.

Response:

As part of Norfolk Power's commitment to providing a safe, robust and reliable distribution system, a SCADA initiative commenced in 2004 to install telemetry at each of the Municipal Distribution Stations and Bloomsburg Transformer Station.

In 2010, there was an opportunity to connect to 2 of the existing Municipal Stations via a secure and dedicated fibre optic cable, approximately 18.5km in length. Norfolk Power coordinated this installation in conjunction with Norfolk County's "Broadband for Norfolk" initiative and its provincial partner known as Ontario Ministry of Agricultural Food and Rural Affairs (OMAFRA). Norfolk Power decided to take advantage of this one-time opportunity and pursue this initiative since OMAFRA would fund approximately 1/3 of the cost of the project ($148,985).

In 2011, Norfolk Power continued to expand its connection of SCADA interface points at each of its MS's. A total of 10 new points were planned for connection at various sites across the distribution network. In addition, a redundant communication link was installed at Bloomsburg TS to facilitate emergency back-up requirements.

In 2012, Norfolk anticipates the connection of an additional 5 interface points through a combination of fibre, wireless and standard telephone connections.

25. Ref: Exhibit 2/Tab 3/Sch 2

Norfolk Power's investments in Pole Replacements have fluctuated over the past several years, with a considerable difference in per pole cost (simply dividing total cost by the number of poles replaced). In 2008 the per pole cost was $4,955, in 2009 $4,911 in 2010 $4,971. For 2011 the cost escalates to $6,000 per pole and then back to $4,800 per pole for 2012.

Please provide an explanation and rationale for these fluctuating costs, particularly concerning the forecast for 2011 and 2012.

Response:

There was an error in the cost per pole in 2011. This cost should have been $5000/per pole. The forecast for pole replacements in 2011 has been revised to 50 poles at a total cost of $250,000. Please see reply to Energy Probe Interrogatory #10.

26. Ref: Exhibit 2/Tab 3/Sch 2/p.62

Why has Norfolk Power not provided for any Transformer Purchases to Increase Transformers in Hand, in 2011 or 2012? Has Norfolk Power changed its policies on these transformers?

Response:

Prior to 2011 Norfolk's budgeted projects did not include transformers and new transformers purchases were identified separately. In 2011 Norfolk began including the transformers in each project budgeted. Norfolk is not increasing the number of transformers held in inventory and therefore has no separately identified transformer purchases.

27. Ref: Exhibit 2/Tab 3/Sch 3/p.1

Norfolk Power indicates that it did not have a formal asset management plan in the past but has filed the plan developed in 2010. Norfolk Power cautions that the plan is in its early development stage. What are Norfolk Power's plans to improve the Asset Management Plan? Please provide an outline of the work to be undertaken on the Plan from 2011 to 2014 to improve its usefulness to Norfolk Power.

Response:

Norfolk Power intends on improving the plan by developing quantitative categories for asset health incorporating system performance analysis. This will enable Norfolk Power to quantitatively rate asset life and utilize risk assessment to further prioritize planned work. The foundation of these improvements lies in the collection and organization of specific asset and performance attributes. Norfolk Power is developing plans to gather this information in an efficient and effective manner by leveraging tools such as GIS and Engineering Analysis Software to aid in the development of medium (5 year) and long term (20-25 years) plans. Gathering of greater historical data should allow for better budgeting of reactive work.

28. Ref: Exhibit 2/Tab 3/Sch 3

Norfolk Power shows that its level of capital expenditures will grow from $3.922 million in 2011, to $4.641 million in 2012, to $4.954 million in 2013 and to $5.129 million in 2014. Does Norfolk Power foresee a period of lower capital spending in future years due to the consistently high levels of spending and consistent increases in these 4 years?

Response:

Along with the review of the Asset Management plan, Norfolk Power plans to develop a long term system plan that will enable responsible management of assets on a proactive basis while minimizing reactive replacement of failed assets. Norfolk's goal is to identify long term capital spending requirements and smooth expenditures as appropriate for given economic conditions. Review has not been completed beyond the 2014 forecast and it is therefore difficult for Norfolk Power to commit to a decrease in capital spending at this point in time. Norfolk Power intends to continue employing a methodology of sensible capital spending while maintaining good system performance through responsible asset management.

29. Ref: Exhibit 2/Tab 3/Sch 5

Norfolk Power provides its reliability statistics from 2007 to 2011.

a) Please provide Norfolk Power's reliability scores year-to-date for 2011.

Response:

Norfolk Power's SAIDI and SAIFI based on 3rd quarter totals and include April 28th Windstorm

YTD including Hydro One Loss of Supply

SAIDI 3.496
SAIFI 3.158

YTD excluding Hydro One Loss of Supply

SAIDI 4.032
SAIFI 2.654

b) Has Norfolk Power developed reliability targets for 2012? If so please provide these targets.

Response:

Reliability targets have not been set for 2012. This is normally done at the last Board meeting in December.

c) As it appears that the reliability scores from 2007 to 2011 indicate a good record of service reliability, to what extent has Norfolk Power considered this in its capital spending plans?

Response:

Norfolk Power wishes to continue its good record of reliability and is striving to improve further through sustainable replacement of distribution assets. As such, we have carefully assessed the need to replace assets through an analysis of "end of useful life" criteria. Some assets are being replaced as "run to failure" occurs whereas the majority of assets are being systematically replaced through a prudent and planned process.

Asset Management Plan

30. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.12

Norfolk Power indicates that it expects that all NPDI owned poles will have a unique ID assigned, be mapped onto the GIS system and have associated attribute and condition data, by the end of 2011. Has Norfolk Power met this goal by the end of 2011 and if not, when is this expected to be completed? How has this data contributed to the planed number of poles that are set for replacement in 2012?

Response:

By the end of 2011, Norfolk Power will have all ID's assigned to poles, and captured attributes associated with these poles. This data has not contributed to 2012 plans, however, moving forward it will assist in providing better information on deciding future pole replacements.

31. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.32

Norfolk Power indicates that vegetation management (tree trimming) is scheduled on a 4-year and 7-year cycle for urban and rural service areas, respectively; but that Norfolk Power will in the future combine activities for both areas and scheduled on a 5-year cycle.

a) Why has Norfolk Power decided to increase the frequency of tree trimming?

Response:

Norfolk has found that while on a 4 and 7 year cycle, additional tree trimming was required to keep up with growth. A 5 year cycle will not increase expenses, (a small decrease is forecast for 2012), but will allow for a systematic approach across the distribution territory.

b) Why has Norfolk Power decided to combine both urban and rural areas in terms of frequency?

Response:

Norfolk's territory is mostly rural, but spotted with several small urban areas throughout it. Power feeders run through both urban and rural areas. To improve reliability on a feeder, it was determined that tree trimming the entire length of the feeder would prove more beneficial than completing only a portion from year to year.

c) What evidence has Norfolk Power relied on to make this decision?

Response:

In changing to a combined cycle for urban and rural, Norfolk Power coordinates maintenance on a per feeder basis and eliminates back-tracking the same section of line for trimming, sometimes in consecutive years. In addition, as previously stated, the cost of a 5 year cycle is similar to current tree trimming expenses.

d) Was a cost/benefit analysis performed?

Response:

There was no formal cost benefit plan completed. However, total cost of tree trimming is expected to remain the same (small decrease forecasted for 2012) while benefits in planning and coordination with maintenance schedules are anticipated. Also it is anticipated that Norfolk will experience a reduction in outages due to a more thorough tree trimming plan. Cost benefit will be reviewed moving forward as further data is collected.

e) When will this increase in tree trimming take place?

Response:

Due to the condition of vegetation growth, Norfolk Power has for the past 4 years been tree trimming beyond the 4 and 7 year cycle. A standard 5-year cycle will begin in 2012.

f) Is there an additional cost of moving to a 5 year cycle?

Response:

No additional costs are anticipated.

32. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.38

Norfolk Power indicates that a Feeder Analysis Report is produced and the 4 worst-performing feeders are identified. Please provide a copy of this report and if not included in the report, provide an analysis of the feeder performance and how Norfolk Power addressed this performance in its plans for 2011 and 2012.

Response:

See attached 2010 and 2011 YTD worst performing feeder reports for the 27.6 kV feeders. The majority of the worst performing feeders involve animal contact and unknown causes which are addressed as part of the maintenance plan. Animal guards are included in the 2012 maintenance budget to address this issue.

Please see Appendix 7 Worst Performing Feeders Board Staff IR 32.

Green Energy Plan

33. Ref: Exhibit 2/Appendix C – Green Energy Plan

Please confirm that Norfolk Power is not seeking a prudence review of the GE Plan in this proceeding. If not seeking a prudence review, please provide the rationale for deferring this review until the next rebasing application.

Response:

Norfolk confirms it is not seeking a prudence review of its Green Energy Plan.

In its original application, (Exhibit 9, Tab 6) Norfolk requested a Funding Adder based on its Green Energy Plan. The funding adder was based on the estimated costs to complete expansion and enabling projects to accommodate the number of applicants for microFIT and FIT generation. Norfolk notes that the net cost of the projects has been less than originally anticipated. In addition the timing of some projects has been delayed by applicants shifting capital spending to future years. For these reasons, Norfolk requests to withdraw its application for a Funding Adder at this time. Instead Norfolk proposes to return with a new Funding Adder application at a future time after it has further experience with these expenses to draw upon.

34. Ref: Exhibit 2/Appendix C – Green Energy Plan, p.2 & OPA Letter of Comment

The statistics provided at page 2 of the Plan indicate that 155 microFIT and 14 FIT applications have been received. The OPA Letter of Comment indicates that:

"The OPA has received 32 capacity allocation exempt FIT applications, 3 capacity allocation required FIT applications and 159 microFIT applications to NPDI's system for a total of 33.59 MW of FIT applications and 1.546 MW of microFIT applications. At this time, 30 microFIT applications have been connected and 22 microFIT applications have been terminated (leaving a total of 1.0393MW of microFIT applications to be connected)".

a) Please reconcile the number of microFIT and FIT applications received by Norfolk Power and the OPA.

Response:

Norfolk Power reviewed the number of microFIT applications via a data export from the OPA's microFIT LDC Admin web application at 15:00hrs on June 30, 2011. The number of applications reported at that time was 155. The OPA Letter of Comment states;

"To date, the OPA has received 32 capacity allocation exempt FIT applications, 3 capacity allocation required FIT applications and 159 microFIT applications to NDPI's system for a total of 33.59 MW of FIT applications and 1.546 MW of microFIT applications. At this time, 30 microFIT applications have been connected and 22 microFIT applications have been terminated (leaving a total of 1.0393 MW of microFIT applications to be connected)."

Norfolk Power is not certain which date the OPA is referencing in the statement above. It is reasonable to believe that if the OPA reviewed the number of applications on a date later than June 30, 2011, four (4) additional applications (for a total of 159) could have been filed with the OPA. As of November 7, 2011 there were 232 microFIT applications.

With respect to the number of FIT applications, Norfolk Power reviewed the number of FIT applications via a data export from the OPA's FAME web application at 15:10hrs on June 30, 2011. The number of applications reported at that time was 14. Norfolk Power recognizes there was a reporting error and this number should have been stated as 15 including 12 capacity allocation exempt FIT applications and 3 capacity allocation required FIT applications. As stated by the OPA in its conclusion section of the comment "the OPA notes that it has received some additional capacity allocation exempt FIT applications as noted above, which have not yet been posted on the FAME website". This is likely the cause of the discrepancy.

b) Please comment on what appears to be a high termination rate for microFIT projects.

Response:

Norfolk Power is not privy to the details of why applications are terminated by potential distributed generation customers.

35. Ref: Exhibit 2/Appendix C – Green Energy Plan/p.6

With regard to the Board's filing requirements *Filing Requirements* Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397], (the "Filing Requirements") Part V, p.11 at Part V, Section 2, bullet point 4:

"…the method and criteria that will be used to prioritize expenditures in accordance with the planned development of the system".

At page 6 of the Norfolk Power GE Plan, Norfolk Power states:

"NPDI is in the process of standardizing its approach to connecting renewable generators to streamline the practice through standardized application forms, cost assessments and technical requirements documentation. This will help identify and simplify the process for potential generators to improve cost estimation accuracy and reduce the time from conception to connection."

a) Please provide the Board with Norfolk Power's prioritization methodology.

Response:

Due to fact that connection of renewable generators is a regulatory requirement, Norfolk Power strives to meet applicant's commercial operation dates and considers them a high priority. Projects are prioritized on a "first come, first served" basis as Norfolk Power is contacted by Generators and leads them through our connection process.

b) Please indicate how the prioritization is applied to the projects identified for implementation in the coming 5 years.

Response:

Norfolk Power has not encountered any conflict with regards to prioritization of FIT or MicroFIT projects and intends on employing the "first come, first served" methodology for the foreseeable future.

36. Ref: Exhibit 2/Appendix C – Green Energy Plan

At page 2 of the GE Plan, Norfolk Power indicates that it does not currently have capacity limitations on its feeders or at Bloomsburg MTS, but notes that,

"…potential circumstances that could limit renewable generation connections include anti-islanding measures on lightly loaded feeders, reverse power flow limitations, Transformer/Distribution Station thermal capacity and short circuit capacity".

Norfolk Power also states at page 6 that,

"…the plan includes system expansions and enhancements necessary to safely connect renewable generators while maintaining power system quality expectations for existing load customers".

a) With regard to the *Filing Requirements*, Part IV, p.7, bullet #5 do present plans to connect renewable energy projects have any impacts on embedded distributors?

Response:

Present plans do not have any impacts on embedded distributors.

b) Will the connection of renewable projects thus far identified in the GEA Plan have a significant impact on the Norfolk Power distribution system? If yes, will immediate upgrades be required, ie. in 2012?

Response:

Based on the current knowledge of renewable projects in Norfolk Power's territory, some expansion upgrades are required, however, until detailed designs and applicable studies are completed this is limited to the estimates provided.

c) Please expand Table 3.9 found at Exhibit 2/Tab 3/Sch2/p.56 to the remainder of the 5-year planning horizon for the projects that have already been identified. Using the table below as a guide, please indicate the work that will be undertaken, and the feeder associated with it.

Response:

Please see tables below.

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
6 Evans St	22M5	10-Nov-11	SYSTEM EXPANSION ACTIVITIES	
			Replacing a transformer to a large MVA size	$25,000
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
55 Donly Dr	22M5	31-Dec-11	SYSTEM EXPANSION ACTIVITIES	Not Applicable
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
227 Main St	10F1	31-Dec-11	SYSTEM EXPANSION ACTIVITIES	Not Applicable
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
510 Main St	22M1	Spring 2012	SYSTEM EXPANSION ACTIVITIES	Not Applicable
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
252 Power St	22M1	Summer 2012	SYSTEM EXPANSION ACTIVITIES	
			Replacing a transformer to a large MVA size	$50,000
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
1468 Hwy 6	BLM3	30-Jun-12	SYSTEM EXPANSION ACTIVITIES	Not Applicable
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	Not Applicable

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
Cloet Rd Sun Edison	BLM3	Fall 2012	**SYSTEM EXPANSION ACTIVITIES**	
			Adding or upgrading capacitor banks to accommodate the connection of the connecting customer	To be determined
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	
			Modifications to, or the addition of, electrical protection equipment	To be determined
			The provision of protection against islanding (transfer trip or equivalent)	To be determined
			Tap-changer controls or relays	To be determined
			Replacing breaker protection relays	To be determined
			SCADA system design, construction and connection	To be determined
			Any other modifications/additions to allow for and accommodate 2-way electrical flows (reverse flows)	To be determined
			Communication systems to facilitate the connection of renewable energy generation facilities	To be determined

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
UDI Pt Ryerse WindFarm	22M5	30-Jun-13	**SYSTEM EXPANSION ACTIVITIES**	Not Applicable
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	
			Modifications to, or the addition of, electrical protection equipment	To be determined
			The provision of protection against islanding (transfer trip or equivalent)	To be determined
			Bidirectional reclosers	To be determined
			Replacing breaker protection relays	To be determined
			SCADA system design, construction and connection	To be determined
			Communication systems to facilitate the connection of renewable energy generation facilities	To be determined

d) Will system expansion/REI activities result in premature asset replacements? When applicable please give an estimate of the remaining useful life of the "replaceable" asset and indicate in each case whether there is a residual value.

Response:

Norfolk confirms that some known projects will require replacement of plant with remaining useful life. Please see the following table.

Project name	Asset Useful Life Remaining	Residual value
6 Evans St	15 yrs	$2,700
252 Power St	18 yrs	$3,500

37. Ref: Exhibit 2/Appendix C – Green Energy Plan

The nature of the work to be undertaken by distributors to connect renewable generators has been classified within three categories, namely Connection, Expansion, and Renewable Enabling Improvement ("REI"); each giving rise to a different cost responsibility split between generators and distributors. From figures shown on Page 3 of the Plan, will some generator connections require work in more than one category (as specified above)?

Response:

Norfolk confirms that some generator connections require work in more than one category.

a) Please provide the statistics on Page 3 in terms of capacity units rather than "per connection".

Response:

The current forecast for 2011 MicroFIT projects are based on the following:

Estimated Offers to Connect Issued: 1000kW
Estimated Generators Connected: 500kW (based on 50% of offers to connect)
Estimated Basic Connection Charge per 10kW: $1,266
Estimated Expansion Cost per 10kW (limited to 30% Connected kW = 150kW): $5,180 (See Note 1. Below)
Estimated Total Generator Connection Costs for 2011: $141,000

Note 1: Norfolk Power estimates that only 30% of the connections will require Expansions

The current forecast for 2011 FIT projects (<=250kW) is based on the following:

Estimated Capacity of Generators Connected: 500kW
Estimated Basic Connection Charge per kW: $64.00
Estimated Expansion Cost per kW: $28.00
Estimated Total Generator Connection Costs for 2011: $46,000

The current forecast for 2011 FIT projects (>250kW but <=10MW) is based on the following:

Estimated Capacity of Generators Connected: 1000kW
Estimated Enhancement Cost per kW: $122.00
Estimated Expansion Cost per kW: $33.00
Estimated Total Generator Connection Costs for 2011: $188,000

b) Please explain why expansion costs shown on page 3 for MicroFIT projects are limited to 30% of generator connections. (whereas the DSC provides for $90,000/MW relative to expansion costs).

Response:

To clarify, Norfolk Power estimated that only 30% of the estimated MicroFIT projects forecast would require expansions.

c) In order to understand the amount of work involved, please complete the table below.

Response:

Please see table below.

	Number of Projects per Category of Work					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Connection						
≤10kW	50	50	40	30	20	10
>10kW to ≤250kW	6	6	5	5	4	3
>250kW	2	4	3	2	2	1
Expansion						
≤10kW	15	15	12	9	6	3
>10kW to ≤250kW	6	6	5	5	4	3
>250kW	2	4	3	2	2	1
REI						
≤10kW	0	0	0	0	0	0
>10kW to ≤250kW	0	0	0	0	0	0
>250kW	0	2	1	1	0	0

d) To clarify cost responsibilities, please expand Table 3 on page 6 by completing the table below.

Response:

Please see table below.

	Expected CAPEX						Expected Capital Contribution					
	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
Connection												
≤10kW	$63,000	$63,000	$51,000	$38,000	$25,000	$12,500	$63,000	$63,000	$51,000	$38,000	$25,000	$12,500
>10kW to ≤250kW	$32,000	$32,000	$28,000	$28,000	$23,000	$16,000	$32,000	$32,000	$28,000	$28,000	$23,000	$16,000
>250kW	$39,000	$92,000	$60,000	$39,000	$39,000	$15,000	$39,000	$92,000	$60,000	$39,000	$39,000	$15,000
Expansion												
≤10kW	$78,000	$78,000	$62,000	$47,000	$31,000	$15,500	$64,500	$64,500	$51,200	$38,900	$25,600	$12,800
>10kW to ≤250kW	$14,000	$14,000	$10,000	$10,000	$8,000	$7,000	$0	$0	$0	$0	$0	$0
>250kW	$66,000	$585,000	$296,000	$294,000	$51,000	$30,000	$0	$10,000	$10,000	$0	$0	$0
REI												
≤10kW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
>10kW to ≤250kW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
>250kW	$122,000	$155,000	$105,000	$83,000	$0	$0	$0	$0	$0	$0	$0	$0

*Note that the 2011 Connection costs and associated Capital Contributions for generators >250kW were omitted from the submitted GEA Plan in error.

38. Ref: Exhibit 2/Appendix C – Green Energy Plan & Exhibit 9/Tab 6/Sch 1/p.3

OM&A costs associated with the implementation of the GE Plan are not reflected in Norfolk Power's application.

a) Please confirm that no additional human resources will be required to implement the GE Plan.

Response:

Norfolk has attempted to implement the GE Plan without increasing staff. However, the amount of time required to complete these projects is significant to our engineering department to such an extent that Norfolk is re-evaluating its plan and may need to hire an additional Technologist.

b) Please indicate what OM&A expenditures, if any, will be associated with the capital expenditures at Table 3.

Response:

At this point in time expenses have been related to the initial connection of these generators and OM&A expenditures have not been fully developed and are currently unknown.

39. Ref: Exhibit 9/Tab6/Sch1/p.2/Table 6.1Renewable Capital Investment If applicable, please use any revised CAPEX figures to re-evaluate overall connection cost responsibilities and derive the subsequent direct benefits accruing to Norfolk Power ratepayers.

In addition, if applicable, please use revised CAPEX & OM&A figures and provide an adjusted estimate of the funding adders.

Response:

This question is no longer applicable as Norfolk has requested to withdraw its funding adder application.

Smart Grid

40. Ref: Exhibit 2/Appendix C – Green Energy Plan

The Norfolk Power GE Plan appears to focus exclusively on the connection of renewables with no Smart Grid related expenditures. The *Filing Requirements* Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397], Part V, p.18 presently limits smart grid activities to: "smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training".

Please confirm that Norfolk Power is not planning to undertake any of the eligible activities over the Basic Plan planning horizon? Why is Norfolk Power not planning for any Smart Grid related activities at this time?

Response:

Norfolk Power is not planning to undertake any of the eligible activities over the Basic Plan planning horizon and is not planning for any Smart Grid related activities due to limited resource availability.

Load Forecast

41. Ref: Exhibit 3/Tab 2/Sch 1/p. 3/Table 2.1

Please provide a year-to-date update of 2011 actual kWh consumption for Norfolk Power. Is actual consumption for the Bridge year tracking expected load? Is there evidence that the load forecasts for 2011 and 2012 may need adjustment? Why or why not?

Response:

Please see table below that shows year-to-date 2011 actual kWh consumption for Norfolk Power (January to August). Also included is the predicted consumption based on the load forecast for 2011 year-to-date (January to August).

	Actual Purchased Power	Predicted Power Purchased	Variance
Jan-11	32,485,439.10	33,810,713.60	3.9%
Feb-11	29,660,293.63	31,260,189.57	5.1%
Mar-11	29,778,711.63	30,844,640.28	3.5%
Apr-11	26,184,532.20	27,968,687.60	6.4%
May-11	25,783,818.45	27,885,938.41	7.5%
Jun-11	28,197,702.53	30,253,940.19	6.8%
Jul-11	35,364,831.54	32,769,774.76	-7.9%
Aug-11	32,366,281.18	31,961,994.58	-1.3%
	239,821,610.26	246,755,878.99	2.8%

42. Ref: Exhibit 3/Tab 2/Sch 1/p.10/Table 2.5

Table 2.5 shows a reasonable track record of actual vs predicted load from 2003 to 2009. In 2010 a much greater variance is reported. Please provide an explanation for the 2010 forecast results showing this larger variance.

Response:

A review of the data supporting the 2010 predicted value indicates that the actual Cooling Degree Day results are much higher than average which is causing the variance in the 2010 predicted value compared to the actual results to be around 1.7%. However, if the average Cooling Degree Day values were used in the 2010 prediction the variance would be about (0.1%)

43. Ref: Exhibit 3/Tab 2/Sch 1/p.11

Norfolk Power indicates that it makes a manual adjustment to reflect the CDM savings target for 2011 and 2012. Does Norfolk Power have any evidence for 2011 to indicate that his manual adjustment is appropriate? Is there evidence in actual CDM results for 2011 that may indicate that the load forecast CDM adjustment for 2012 is not accurate?

Response:

Norfolk Power has reviewed the 2011 load numbers as at September 30, 2011. The kWh savings as at September 30, 2011 showed results of very close to 7.5%. Extrapolating this percentage over the remainder of the year should allow Norfolk Power to meet its 2011 CDM savings target.

There is no evidence in actual CDM results for 2011 that might indicate that the load forecast CDM adjustment for 2012 is not accurate.

44. Ref: Exhibit 3/Tab 2/Sch 1/p.12

Norfolk Power indicates that it uses the geometric mean of 1.3% per year from 2003 to 2010 to forecast customer connections for 2011 and 2012. Considering the deterioration in economic conditions evident in 2011 is it still realistic to make this assumption? What is the year-to-date increase in residential customer connections for 2011?

Response:

Norfolk Power feels that using this geometric mean per year from 2003 to 2010 to forecast customer connections for 2011 and 2012 is reasonable.

The year-to-date increase in residential customer connections in 2011 is 74(January 1, 2011 to September 30, 2011). This increase during the first nine months of 2011 might equate to an annual increase of approximately 99 new customers. This would work out to a .6% increase in its residential customer count for 2011.

As of Sept 30, 2011 there are 106 new customers and 23 disconnected services giving 83 "net new" customers that have been connected. Norfolk believed an average from 2003 thru 2010 was sufficient to calculate a reasonable average. However based on the actual year to date this may be too aggressive.

45. Ref: Exhibit 3/Tab 2/Sch 1/p.13/Table 2.10

Regarding Usage per Customer Connection, can Norfolk Power explain:

a) Why the usage per customer in the Residential class grows in 2010 when this measure has declined over the previous years?

Response:

Based on the Power Purchased Model variable "Cooling Degree Days" it appears that 2010 was a very hot summer. The number of "Cooling Degree Days" for 2010 was 365. The corresponding number for 2009 was 151, for 2008 was 228, and for 2007 was 291. The increased use of air conditioning during 2010 is most likely the largest single contributing factor to explain why the usage per customer in the Residential class grows in 2010 when this measure had declined in previous years.

b) Why the Usage per Connection increases so significantly in the Street Lighting and Sentinel Lighting classes in 2010?

Response:

Usage per Connection increases in Street Lighting and Sentinel Lighting classes in 2010 were significant due to unbilled revenues from 2009 that got caught up in 2010.

Other Distribution Revenue

46. Ref: Exhibit 3/Tab 3/Sch 1

Table 3.1 shows that Late Payment Charge revenue drops from $155,219 in 2009, to $86,593 in 2010.

a) What is the reason for this significant drop in revenue?

Response:

Norfolk's share of the Late Payment Penalty (LPP) Class Action (EB-2010-0295) was $55,876.38. Norfolk did not seek recovery of this amount from its customers and as it was a charge related to the collection of Late Payment Charges, Norfolk posted this expense as an offset to Late Payment Charge revenue for 2010. Without this charge, Norfolk's Late Payment Charges for 2010 would have been $142,470.

b) What are the assumptions that were made to forecast an increase to $138,000 in both 2011 and 2012?

Response:

The assumptions made for 2011 and 2012 are that Late Payment Charge revenues should return to normal levels. The $138,000 figures are very close to the average for the years 2008, 2009 and 2010 ($124,516, $155,219 and $142,470).

47. Ref: Exhibit 3/Tab 3/Sch 1

Table 3.1 shows that Miscellaneous Service revenue drops from $101,896 in 2010 to a projected $88,000 in 2011.

a) What is the reason for this significant projected drop in revenue in 2011?

Response:

The revenues anticipated in 2011($88,000) more accurately reflect the average Miscellaneous Revenues for the years 2006 through 2010($91,500). In reviewing the Miscellaneous Service Revenues for 2011, January through September, the balance is approximately $65,757. Extrapolating this figure over a full year would mean a total Miscellaneous Service Revenue for 2011 of $87,677 which is very close to the expected revenue of $88,000 as per Table 3.1. Declines in Disconnect/Reconnection at Meter (During & After Hours) revenues in 2011 have contributed to this lower Miscellaneous Services Revenues total.

b) What are the assumptions that were made to forecast the identical level in 2012?

Response:

The assumption for the 2012 forecast was that no significant changes should occur in Miscellaneous Service Revenues over 2011 forecasted numbers.

48. Ref: Exhibit 3/Tab 3/Sch 1

Table 3.1 shows that Other Income and Expenses revenue drop from $147,454 in 2011 to a projected $95,880 in 2012. Please provide further detail of the components that make up this change and the rationale for the 2012 forecast.

Response:

As described in Exhibit 3, Tab 3, Schedule 2, Page 2 of 2, the decrease is mainly due to the decrease in the Special Purpose Recovery of ($57,574).

Operating Costs

49. Ref: Exhibit 4/Tab 1/Sch 1/p.2

Please provide an update of Norfolk Power's Operating Costs, year-to-date in 2011. If there are significant discrepancies (in the major line items) with the forecast costs filed for 2011, please provide the reasons. Also please discuss if the 2012 forecast will be affected, why or why not?

Response:

Please see table below:

Description		Jan 1 to Sep 30 2010	Jan 1 to Sep 30 2011	Variance $	Variance %
Operations		817,093	860,171	43,079	5.3%
Maintenance		824,838	890,428	65,590	8.0%
Billing & Collecting		795,760	729,589	(66,171)	-8.3%
Community Relations		24,200	25,568	1,368	5.7%
Administrative & General Expense		1,194,752	1,255,334	60,582	5.1%
Total OM&A Expense		**3,656,644**	**3,761,091**	**104,447**	**2.9%**

Norfolk believes the 2012 forecast will not be affected. The only significant difference is in Billing and Collecting expenses, however the 2012 forecast is based on a number of changes related to the use of smart meters, which are not related to the expenses in 2011.

50. Ref: Exhibit 4/Tab 1/Sch 1/p.6

Table 1.9 shows Norfolk Power's OM&A cost per customer to be $269 in the 2012 Test Year, up from the $226 2008 Board Approved level. Does Norfolk Power track OM&A cost per customer of other utilities in its cohort (Mid-Size Southern Low and medium Undergrounding) comprised of Innisfil Hydro Distribution, Niagara Peninsula Energy, Orillia Power Corporation, Haldimand County Hydro and Canadian Niagara Power? Can Norfolk Power provide a comparison of OM&A cost per customer with its cohort companies from 2008 to 2010?

Response:

Norfolk Power does track OM&A cost per customer of other utilities in its cohort.

Please see table below which compares Norfolk Power OM&A cost per customer with its cohort companies from 2008 to 2010.

		2008	2009	2010
Norfolk Power Distribution		$ 277	$ 238	$ 257
Innisfil Hydro Distribution		$ 246	$ 254	$ 266
Niagara Peninsula Energy		$ 255	$ 257	$ 262
Orillia Power Corporation		$ 298	$ 302	$ 325
Haldimand County Hydro		$ 338	$ 332	$ 325
Canadian Niagara Power		$ 285	$ 303	$ 282

51. Ref: Exhibit 4/Tab 1/Sch 1/p.9

Table 1.11 shows Norfolk Power's cost for Consultants (for Regulatory Matters) to have increased from $41,551 in 2008 to $120,000 in the 2012 test year. Please provide a rationale for an increase of this magnitude and also provide a further breakdown of the 2012 costs that total to $120,000.

Response:

Norfolk has included in this amount the total costs related to the 2012 Cost of Service application, although some costs will occur in 2011. This appeared appropriate based on the spreadsheet provided which calculated 25% of this amount for recovery in the annual revenue requirement.

Norfolk estimates the following expenses for the 2012 Cost of Service application:

LRAM 3rd Party review and application	$15,000
PILs application	$15,000
Rate consultant	$45,000
Legal Expenses	$45,000
Total	$120,000

52. Ref: Exhibit 4/Tab 1/Sch 1/p.10

Norfolk Power indicates that it has not made any assumptions for inflation in the 2012 test year but has budgeted based on existing prices and increases if known. Please provide any known increases included in the Test Year OM&A forecast and also comment on why a general inflation assumption is not used for the test year forecast.

Response:

Norfolk has used the following increases:
Union Wages: 1.5% in January 2012, 1.5% in July 2012.
Management Wages: 3% for 2012.
Pension costs: Increased based on wages and known premium increases as described in the response to Board Staff Interrogatory 61.

Other increases in OM&A accounts are primarily due to changes in activity. For example, under Billing and Collecting, the charges for 5310 – Meter Reading Expenses are based on the expectation that the costs related to smart meters will be included in OM&A and the amounts were determined based on current costs and expected volumes, as described in Exhibit 4, Tab 2, Schedule 3, p11. Norfolk felt it more appropriate to estimate the expenses on this basis rather than by applying a general inflation assumption.

53. Ref: Exhibit 4/Tab 2/Sch 2/p.1

Table 2.1 shows that under Operations, Norfolk Power's Meter Expense grows from $124,009 in 2010, to $145,000 in 2011 and on to $214,000 in the test year. Why is this expense increasing at this pace, even as Norfolk Power has essentially completed its Smart Meter deployment?

Response:

The Meter Expenses from Table 2.1 (Exhibit 4, Tab 2, Schedule 2) are reproduced below.

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5065 - Meter Expense	$191,034	$208,371	$142,115	$124,009	$145,000	$214,300

The expenses in this account are related to meter testing, verification and re-sealing meters, etc. With the installation of new meters during 2009, 2010 and 2011 activity of this type was reduced. With the completion of the Smart Meter deployment Norfolk anticipates expenses will return to similar levels seen prior to the smart meter program.

54. Ref: Exhibit 4/Tab 2/Sch 2/p.2

Table 2.3 shows that under Billing and Collections Expense, Norfolk Power's Meter Reading Expense grows from $199,978 in 2010, drops to $120,900 in 2011 and then grows to $234,395 in the test year. (Board staff acknowledges that the $234,395 amount is broken out at Exhibit 4/Tab2/Sch3/p. 11) Why is this expense falling in the bridge year, but then increasing in the test year?

Moreover, at Exhibit 4/Tab2/Sch3/p. 2, under Third Party Services, Norfolk Power indicates a reduction in meter reading expenses of $156,000 in the test year. Please provide a comprehensive picture of the total Meter Reading expense, from 2008 to 2012, explaining the impact of all aspects of this activity and how costs are calculated for the test year.

Response:

Meter reading expenses from the application have been reproduced in the table below for reference.

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5310 - Meter Reading Expense	$215,527	$198,725	$185,789	$199,978	$120,900	$234,395

During the period 2008 thru 2011, Norfolk has utilized an external contractor for manual or 'foot' reads of meters. During 2011 Norfolk has moved to electronic reading of the smart meters installed during the past 2 years. The cost of reading the smart meters has been reported in the smart meter deferral account, while the cost of reading the meters under the traditional manual method has continued to be reported in 5310 – Meter Reading Expense. In 2012 it is anticipated that, through this application, the smart meter deferral account will no longer be utilized and all costs related to reading the smart meters will be reported in 5310 – Meter Reading Expenses. Norfolk has forecast these expenses at $234,395 and as noted in the interrogatory, a breakdown of these expenses is available in Table 2.13, Exhibit 4, Tab 2, Schedule 3. In addition, following this table on pages 11 and 12 is a complete explanation of each of the charges related to this expense and how they were calculated.

The 2011 expense of $120,900 was an estimate based on moving to TOU billing in July and eliminating foot reads by the end of that month. However, while TOU billing began in July foot reads have not ceased due to communication problems with Norfolk's Advanced Metering Infrastructure, provided by Sensus. With the Read Interval Success rate significantly below the acceptable level, Sensus has indicated the need for three additional Tower Gateway Base Stations, which are scheduled to be installed by the end of 2011. However until the communication issues have been resolved, Norfolk will continue with foot reads for over 2,000 customers.

While the number of customers dependant on foot reads has been reduced significantly, the location of these customers, spread throughout Norfolk's service territory, requires a significant amount of time for completion. Meter reading expenses as of the end of September 2011, were $152,645 and will continue at a cost of approximately $11,000 per month until the end of the year, for a total cost of $191,000.

On page 2 of Exhibit 4, Tab 2, Schedule 3 Norfolk reported meter reading expenses would be decreased by $87,000, to $156,000. However this was incorrect and should have stated expenses would be reduced by $79,000 to $121,000. Also, this was in reference to foot reads only. As part of the Cost Driver analysis, that this reference is part of, Norfolk indicated the $234,395 required for Smart Meter – Electronic Reading Expenses. Although both of these are meter reading expenses and the net amount could have been reported, Norfolk separated them to provide increased transparency.

55. Ref: Exhibit 4/Tab 2/Sch 2/p.2

Table 2.2 shows that total maintenance expenses more than double from the 2008 approved amount to 2008 actual. Can Norfolk Power provide an explanation for this increase?

Response:

The difference between total maintenance expenses from the 2008 actual expenses to the 2008 approved amount was $789,059 ($1,507,433-$718,374). This difference is accounted for as follows:

USoA	Distribution Expenses - Maintenance	2008 Board Approved	2008 Actual	Variance
5105	Maintenance Supervision and Engineering	51,652	57,207	5,555
5110	Maintenance of Structures	8,709	6,622	-2,087
5112	Maintenance of Transformer Station Equipment	8,016	2,885	-5,131
5114	Maintenance of Distribution Station Equipment	61,338	59,352	-1,986
5120	Maintenance of Poles, Tow ers and Fixtures	40,967	72,645	31,678
5125	Maintenance of Overhead Conductors & Devices	138,993	393,599	254,606
5130	Maintenance of Overhead Services	30,138	17,225	-12,913
5135	Overhead Distribution Lines & Feeders - Right of Way	261,066	571,378	310,312
5145	Maintenance of Underground Conduit	64	0	-64
5150	Maintenance of Underground Conductors and Devices	5,774	77,615	71,842
5155	Maintenance of Underground Services	11,673	50,729	39,056
5160	Maintenance of Line Transformers	72,843	190,502	117,659
5165	Maintenance of Street Lighting and Signal Systems	0	0	0
5170	Sentinel Lights - Labour	0	0	0
5172	Sentinel Lights - Materials and Expenses	0	0	0
5175	Maintenance of Meters	27,142	7,674	-19,468
5178	Customer Installations Expenses - Leased Property	0	0	0
5195	Maintenance of Other Installations on Customer Premise	0	0	0
	TOTAL MAINTENANCE EXPENSES	718,374	1,507,433	789,059

Storm Expenses

The 2006 Storm actual expenses ($97,342) were not included in the Board Approved 2008 expenses. The grossed up storm expenses that should have been included in the 2008 Board Approved costs was $109,023, understating Norfolk's revenue requirement in 2008 by this amount.

Tree Trimming Services

In 2008 a significant amount of work tree trimming was required to complete a backlog of uncompleted work. Total cost of this work was $571,378 compared to the Board approved amount of $261,066, an excess of $310,312.

PCB Testing Program

Norfolk tests transformers for PCB content and replaces any defective equipment it finds as a result of the testing. In 2008 Norfolk instigated a large PCB replacement program which resulted in $117,659 of expenses in excess of Board approved. In addition, while testing transformers, other deficiencies that were found were often repaired at the same time and not reported separately by line staff.

Overhead & Underground Maintenance Expenses

In 2008 Norfolk experienced an increase in service calls for Overhead and Underground Maintenance ($293,662 in excess of 2008 Board Approved). In addition there were maintenance projects required in 2008 which included unforeseen maintenance work on underground services and the replacement of cross arms on poles in Port Dover.

56. Ref: Exhibit 4/Tab 2/Sch 2/p.2

Table 2.3 shows that customer billing expense grows by 21% from $485,550 in 2011 to $586,501 in the test year. What is the rationale for this steep increase in expense for the test year?

Response:

The change from $485,550 to $586,501 for an increase of $100,951 is primarily the result of a change in the allocation of expenses related to the water and sewer billing services provided by Norfolk. Both of the $485,550 and the $586,501 are net of this allocation of expenses to Norfolk's affiliate NEI. The Gross amount for this account in 2011 is $747,000 and for 2012 is $795,000. The increase in the gross amount by $48,000 is related to a vacancy that was filled part way through 2011 and inflationary increases in wages, as described in Exhibit 4, Tab 2, Schedule 4.

However, in 2011 (and prior years) 35% of this account was allocated to NEI for expenses related to the water and sewer billing services. With the new contract taking effect in 2012, these services will be billed at a fixed amount per bill, which results in approximately 26% of this account that will be allocated, or approximately $71,500 less than the method used in 2011. The rationale for accepting the reduced rate for water and sewer billing, and the actual costs to perform these activities is provided in Exhibit 4, Tab 2, Schedule 5, page 3.

57. Ref: Exhibit 4/Tab 2/Sch 2/p.2

Table 2.3 shows a negative amount (revenue) under Account 5330 – Collection Charges. Please explain what this entry is, why it is growing from 2010 to 2012 and how it relates to the Bad Debt expense in the next line.

Response:

The negative amount (revenue) under Account 5330 – Collection Charges, shown in Table 2.3 is an expense offset to collections expense. This amount represents collection fees charged to customers when their account goes to internal collections status (overdue account). This amount is growing from 2010 to 2012 based on historical growth since 2008 in this account. Due to the economic downturn that began in 2008, Norfolk experienced an increase in the number of accounts that went into arrears. This account is not related to Bad Debt expense.

58. Ref: Exhibit 4/Tab 2/Sch 2/p.2

Table 2.3 shows that Bad Debt expense falls in 2010 from 2009 levels, and then grows significantly in 2011 and then again in the test year. Please explain the significant increase in light of the fact of a continuing economic recovery through 2011 and 2012.

Response:

In the year 2009, Norfolk accelerated the time period for write offs which resulted in a one-time increase in the Bad Debt Expense amount during 2009. For 2010, Norfolk was back to the “usual” write-off period but experienced several timing issues that resulted in a lower-than-normal Bad Debt Expense for 2010.

In preparing the 2011 & 2012 forecasts for this application, Norfolk used an average of historical years’ bad debt expense (2007 to 2010) to estimate 2011 & 2012 expense and assumed that write-offs affecting bad debt expense and the allowance for doubtful accounts will return to normal levels of activity.

59. Ref: Exhibit 4/Tab 2/Sch 3/p.3

Norfolk Power explains the level of tree trimming service expense, with a slight reduction in 2012. In light of the desire of Norfolk Power to change the frequency of tree trimming from a 4 and 7 year cycle to a common 5 year cycle, how is the expense budget for tree trimming affected?

Response:

Please see Norfolk response to Board Staff Interrogatory #31.

60. Ref: Exhibit 4/Tab 2/Sch 5/p.2&3

After Norfolk Power's successful bid to continue to provide billing and collecting services for Norfolk County's water and sewer services, why did Norfolk Power not pursue a similar contract to continue providing billing services for NEI hot water rentals?

Response:

Norfolk has taken steps to separate business operations from its affiliate NEI and to ensure compliance with ARC. At the time the decision was made to discontinue providing billing services for hot water rentals Norfolk believed this decision was required to be ARC compliant.

Pension Costs and Post Employment Benefits

61. Ref: Exhibit 4/Tab 2/Sch 4/p.8

Norfolk Power indicates that OMERS released a 3-year plan indicating a 1% per year increase in OMERS premiums beginning in 2011 and then includes excerpts from an e-mail from OMERS outlining the 2012 increase. At Table 2.20 pension premium costs are shown to increase 13% in 2011 and 27% in 2012.

a) Please reconcile these increases with the 1% in 2011 (as noted above) and also provide a detailed breakdown of how the 2011 and 2012 amounts were determined.

Response:

The OMERS announcement of a 1% increase in premiums relates to the rate increase, not the increase in expense. For example, the first tier of premiums increased from 6.4% in 2010 to 7.4% in 2011. This 1% increase in premiums is a 15.6% increase in expense.

The increases in premiums and expenses are summarized below:

OMERS Premiums (% of Pensionable Earnings)	**2010**	**2011**	**2012**
On earnings up to CPP limit	6.4%	7.4%	8.3%
Increase in Premium Expense		***16%***	***12%***
On earnings over the CPP limit	9.7%	10.7%	12.8%
Increase in Premium Expense		***10%***	***20%***

The 2011 estimated amount of $259,445 is 13% higher than the 2010 amount of $229,007 which is consistent with the increased premiums noted above.

The 2012 estimated amount of $329,900 is 27% higher than the 2011 amount, which reflects the increases above, plus the 9.5% increase in total wages as described in Exhibit 4, Tab 2, Schedule 4.

b) Please reconcile the amounts presented in Table 2.20 with pension amounts found in Table 2.19 for 2011 and 2012.

Response:

Reconciliation of Pension Amounts Presented in Table 2.20 and 2.19

	2011	2012
Table 2.20	$259,445	$329,900
Table 2.19	$77,400	$90,500

“Pension Amounts” presented in Table 2.20 relate to OMERS Pension Premium Costs.

Table 2.19 relate to “Accrued Pension and Post Retirement Benefits”. Since they are not the same thing, reconciliation is not possible. Please see Table 2.21 for disclosure of the $77,400 and $90,500.

62. Ref: Exhibit 4/Appendix C

With regard to Pension and Other Post-Employment Benefits:

a) Why was a draft report filed with this application and not a final report? If a final report is available, or if any updates are available, please update this application with those reports.

Response:

The draft report filed was prepared in 2010 as an estimate for 2011. The latest full valuation report was performed as at January 1, 2008 and the figures found in the draft report are an extrapolation of those results. Typically a full report is completed on a triennial basis and Norfolk has engaged Dion-Durrell to perform a full valuation as at January 1, 2011. This report is expected to be completed in December 2011, or January 2012.

b) What is the accounting treatment of the unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011)? What is the proposed regulatory treatment of these amounts – are these amounts incorporated anywhere in the revenue requirement? Please explain.

Response:

As part of the valuation currently underway (see 62, part a), Dion-Durrell has been engaged to identify any changes due to the transition from CGAAP to MIFRS. Norfolk has not proposed any regulatory treatment for these possible gains or losses, nor are any amounts incorporated in the revenue requirement found within the application.

c) In specific, what regulatory treatment is Norfolk Power proposing for the Unrecognized Actuarial Gain of $82,926 that was projected to exist as at December 31, 2010, as per September 17, 2010 Actuarial Report? What is the regulatory impact on pension expense incorporated into rates?

Response:

Norfolk has not recognized this gain on its financial statements nor in the application and therefore does not impact rates.

The unrecognized actuarial gain of $82,926 at December 31, 2010 as per the disclosures prepared on September 17, 2010 will change based on the results of the full valuation as at January 1, 2011. For 2011 under CICA 3461, Norfolk will continue to amortize actuarial gains/losses using the corridor approach described under the standard. The impact on the 2011 pension expense will not be fully known until the results of the full valuation at January 1, 2011 are available. Please also see 62b above regarding the treatment of unamortized actuarial gains or losses upon transition to IAS 19.

d) What were the main drivers for this unrecognized actuarial gain of $82,926?

Response:

There were actuarial gains established at January 1, 2008 (i.e. the date of the last valuation) and the main drivers were: changes in medical claims costs, changes in actuarial assumptions (eg. medical trend rate, salary scale), and demographic changes. More recently, the unamortized actuarial gain/loss was also impacted by an increase in the discount rate assumption from 5.00% to 6.00% at December 31, 2008 and a subsequent reduction in the discount rate assumption from 6.00% to 5.50% at December 31, 2010.

e) Please provide the full Actuarial Valuation as at January 1, 2011.

Response:

Please see response to 62a above.

f) Have Norfolk Power's external auditors audited the September 17, 2010 Actuarial Report (or the final form) and the January 1, 2011 actuarial report? Please provide supporting documentation.

Response:

Norfolk's auditors have not audited the September report as it was a draft only to provide a 2011 estimate. The January 1, 2011 actuarial report is not complete yet. However Norfolk's auditors will review the final report as part of the audit process for the 2011 audited statements.

g) Has Norfolk Power applied the optional early adoption to the IASB's June 2011 revisions to IAS 19, Employee Benefits? The revisions are effective January 1, 2013, but early adoption is permitted. These revisions include the elimination of the option to defer recognition of gains and losses, known as the "corridor method". Please explain if Norfolk Power has early adopted this element of IAS 19 and state whether the impacts of this early adoption are incorporated anywhere in the revenue requirement.

Response:

Norfolk has not adopted this element of IAS 19 and this has not been incorporated within the revenue requirement.

63. Ref: Exhibit 4/Tab 2/Sch 4/p.10

At Table 2.21, Norfolk Power shows the Post-Retirement Benefit amounts from 2008 to 2012. In addition, the 2011 draft Post-Retirement Benefit Report is provided at Appendix C. Please provide a road map from the Report to the amount included for 2011 and how the 2012 amount (13% increase over 2011) was determined.

Response:

The Prepaid Benefit Section of the Dion Durrell Report shows a 2012 estimated liability of $945,253. This is an increase over the 2011 liability of $867,800. The resulting increase in liability of $77,453 ($945,253 - $867,800) was rounded to $77,400 and included in Table 2.21.

Method for Determining the 2011 and 2012 Amounts.

The Total 2011 and 2012 Amounts of $108,379 and $122,408 respectively includes the accrual for the estimated increase in Post Retirement Liability noted above PLUS the estimated premiums (Life Insurance and Extended Health Benefits) paid to Insurance carrier. The method of estimating 2011 and 2012 Premiums & Expenses Paid portion was to take the 2010 Actual of $30,076 and add 3% to estimate the 2011 cost of $30,979. 2012 takes the 2011 estimate and adds another 3% for a total of $31,908.

64. Ref: Exhibit 4/Tab 2/Sch 4/Appendix C

The Report shows that a discount rate of 5.50% was used as at December 31, 2010. Please explain the underlying assumptions that resulted in Norfolk Power choosing 5.50% as the discount rate.

Using the same methodology, what discount rate would Norfolk Power choose as at June 30, 2011 given the current state of the domestic and international bond markets? Please describe the assumptions made in answering the question.

Response:

Norfolk relied on Dion-Durrell's expertise to determine the appropriate discount rate. Norfolk requested Dion-Durrell to assist in answering this interrogatory and provides their response below:

Pursuant to CICA 3461, the discount rate was determined based on a review of "market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of the expected benefit payments". In reviewing market information regarding yields on high quality debt instruments as at the end of 2010, a discount rate of 5.50% was chosen and some of this information is described below.

The Bank of Canada website showed the return on selected Government of Canada benchmark bond yields: CANSIM Series V122544 long term yield, greater than 10 years, of 3.54% at December 2010, and CANSIM Series V122543 bond yields, 10 year, of 3.16% at December 2010. For comparative purposes, the V122544 and V122543 bond yields at December 2009 were 4.07% and 3.60%, respectively.

Reference was also made to market information related to bond yield spreads for Canadian provincial and corporate bonds, i.e. spreads above Government of Canada bond yields. Provincial bond yield spreads were in the range of 0.6% to 0.9% at December 2010. Similarly, yield spreads on Canadian high quality corporate bonds were in the range of 0.9% to 1.8% at December 2010.

The discount rate assumption changes will be finalized as part of the full January 1, 2011 actuarial valuation process. At this time it is estimated (using current information on high quality bond yields) that the discount rate will likely need to be reduced and fall in the range of 4.75% - 5.25%.

Payments in Lieu of Taxes (PILs)

65. Ref: Exhibit 4/Tab 3/Sch 1

Please provide the Federal and Ontario Notice of Assessments, Notice of Reassessments (if applicable), Statements of Adjustments, and any other correspondence with the CRA and Ministry of Finance regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, for tax years 2008 to 2010.

Response:

Norfolk has one outstanding tax filing, for SR&ED.

Please see Appendix 8 Benefact Report Board Staff IR 65.

66. Ref: Exhibit 4/Tab 3/Sch 1

As per “Sch 13 Tax Reserves Bridge” and “Sch 13 Tax Reserves Test” of the PILs Income Taxes Workform there is an amount of $952,575 included as “Other Reserves” in both the bridge and test years.

a) As per the 2010 tax return, this amount may represent regulatory liabilities. Please confirm if this is the case. If this is not the case, please indicate what this amount represents.

Response:

Norfolk Confirms that the amount of $952,575 included as “Other Reserves” in both the bridge and test years presents regulatory liabilities.

b) As per EB-2008-0381, the Board accepted the Settlement Agreement for Issue #4. Complete Settlement for Issue #4 was reached as follows:

“The Parties agree that regulatory assets should be excluded from PILs calculations both when they are created, and when they are collected, regardless of the actual tax treatment accorded those amounts.”

If the $952,575 amount represents regulatory liabilities, please update the PILs evidence to exclude this amount from Schedule 13 Taxes Reserves Bridge and Test, all calculations of regulatory taxable income, and all PILs calculations.

Response:

There was no impact.

Retail Transmission Service Rates

67. Ref: Exhibit 8/Sch 1/p. 13

Norfolk Power indicates that it estimated that 65% of the load previously delivered via Haldimand Hydro will now be routed through Norfolk Power's own transformer station, incurring Network and Line Connection charges from the IESO, but not Transformation Connection charges. The remaining 35% of previous Haldimand load will flow through a Hydro One transformer station, incurring Network, Line Connection and Transformation Connection charges. Please provide justification for using the 65% estimate.

Response:

Norfolk relied on its Control Room Operator to estimate the percentage of load which would be rerouted through Norfolk's transformer station compared to the percentage which would flow through a Hydro One station.

Norfolk used this method of reallocating the transmission volumes to establish rates effective May 1, 2011 as part of its 2011 IRM application (EB-2011-0049). Since that date, the variance in Network charges has been reasonable. Please see the table below outlining the Network Charges monthly variances from May 2011 through September 2011.

	Costs	Revenues	Monthly Variance
May-11	$157,851.85	$142,205.19	$ 15,646.66
Jun-11	$183,242.50	$170,906.04	$ 12,336.46
Jul-11	$215,722.30	$220,667.04	-$ 4,944.74
Aug-11	$186,964.23	$266,697.27	-$ 79,733.04
Sep-11	$171,429.16	$180,680.31	-$ 9,251.15
			-$65,945.81

Deferral and Variance Accounts

68. Ref: Exhibit 9/Tab 2/Sch 1

Regarding 2010 IRM – Group 1 Balances Cleared on an Interim Basis: In Norfolk Power's 2010 IRM Decision EB-2009-0238, the Board approved Norfolk Power's December 31, 2008 balances with carrying charges projected to April 30, 2010 on an interim basis.

The Board was concerned with differences between the amount sought for disposition, which had changed as a result of Norfolk Power conducting an extensive review and rebuild of its Group 1 accounts, and the balances reported in Norfolk Power's 2008 audited financial statements. On page 11 and 12 of the Decision, the Board stated:

"The Board is concerned about the difference between the amount sought for disposition and the balances reported in Norfolk's audited financial statements. The Board notes that Norfolk indicated in its reply submission that it will have its 2008 audited financial statements restated to reflect the rebuilt account balances but that these are not yet available. As a result, the Board will approve the disposition of the December 31, 2008 balances and projected interest to April 30, 2010 as reported by Norfolk but not on a final basis. Any adjustment to the 2008 Group 1 account balances shall be brought forward to the Board in Norfolk's next rate proceeding. For accounting purposes, the respective balance in each of the Group 1 accounts shall be transferred to account 1595 as soon as possible but no later than June 30, 2010 so that the RRR data reported in the second quarter of 2010 reflect these adjustments."

In Norfolk Power's 2011 IRM Decision EB-2011-0049, the Group 1 Balances were not cleared as they did not exceed the preset disposition threshold. On page 7 of this Decision the Board stated:

"Norfolk's Group 1 account balances did not exceed the preset disposition threshold... The Board therefore finds that no disposition is required at this time."

a) Were there any adjustments made to the 2008 Group 1 account balances that were cleared on an interim basis, subsequent to the 2010 IRM decision EB-2009-0238?

Response:

There were no adjustments made to the 2008 Group 1 account balances that were cleared on an interim basis, subsequent to the 2010 IRM decision EB-2009-0238.

b) If the answer to part a) of this question is yes, please explain and provide supporting evidence.

Response:

Not applicable.

c) If the answer to part a) of this question is no, please provide a reconciliation between the December 31, 2008 Group 1 account balances that were cleared in 2010 IRM, and the restated December 31, 2008 Group 1 account balances that were audited by Norfolk Power's external auditor. Please explain any material differences.

Response:

There were no differences between the Group 1 account balances that were cleared in 2010 IRM and the restated December 31, 2008 Group 1 account balances that were audited by Norfolk Power's external Auditor.

The 2010 Audited Financial Statement balances reflect the amounts dispositioned based on EB-2009-0238.

Please see reconciliation below. There are no material differences.

		Restated 2008 Audited Financial Statements	Add: 2009 Projected Interest	Add: 2010 to April 30 Projected Interest	2008 Balance for Disposition	Total Claim from Decision and Order EB-2009-2038 2010 IRM	Difference to Reconcile
LV Variance Account (note 1)	1550	9,218	138	22	9,377	9,377	0
RSVA - Wholesale Market Service Charge	1580	(771,480)	(7,723)	(1,235)	(780,438)	(780,438)	-
RSVA - Transmission Network Charge	1584	10,817	45	7	10,869	10,869	-
RSVA - Retail Transmission Connection Charge	1586	492,840					
(note 2)		(1,457,880)					
		(965,040)	(10,190)	(1,642)	(976,873)	(976,519)	(354)
RSVA - Power (Excluding Global Adjustment)	1588						
RSVA - Power (Global Adjustment Sub-Account)	1588						
(note 3)		91,373	2,456	396	94,225	93,170	1,055
Recovery of Regulatory Asset Balances	1590	206,426	3,362	542	210,330	210,304	26

note 1: Balance of $9,218 is grouped with account 1508 balance on Financial Statements for a total of $340,048 and shown as regulatory asset "Other Deferred Charges"
note 2: Balance of $492,840 is shown on financial statements as regulatory asset "Bloomsburg transformer connection charge" and regulatory liability of $$1,457,880 shown as "Transmission connection services"
note 3: Shown as $91,373 on financial statements as regulatory asset "Power"

69. Ref: Exhibit 9/Tab 2/Sch 1

a) Has Norfolk Power made any adjustments to deferral and variance account balances that were previously approved by the Board, subsequent to the balance sheet date that was cleared in the most recent rates proceeding? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

Response:

Norfolk has not made any such adjustments.

b) Regarding the net balances of Cost of Power for RSVA accounts:

i. Please provide breakdown of energy sales revenue and cost of power expense, as reported in the audited financial statements for 2009 and 2010, by Uniform System of Accounts ("USoA") account number.

Response:

Please see table below.

USoA	2009	Per Audited Financial Statements	Reconciling Amount	2010	Per Audited Financial Statements	Reconciling Amount
4006	$ 12,083,862			$14,241,867		
4025	199,568			104,599		
4030	15,679			16,847		
4035	8,926,127			9,667,443		
4050	106,150			- 584,122		
4055	1,903,273			2,137,866		
4062	2,361,270			2,162,979		
4066	1,621,462			1,842,021		
4068	1,363,675			1,238,705		
4075	182,119			205,575		
	$ 28,763,186	$ 28,763,186	-$ 0	$31,033,780	$ 31,033,780	-$ 0
4705	23,234,659			25,584,500		
4708	2,361,270			2,162,979		
4714	1,621,462			1,842,021		
4716	1,363,675			1,238,705		
4750	182,119			205,575		
	$ 28,763,186	$ 28,763,186	-$ 0	$31,033,780	$ 31,033,780	-$ 0
Gross Margin	$ -	$ -	$ -	$ -	$ -	$ -

ii. Please reconcile the balances to the audited financial statements.

Response:

Please see table above which shows no reconciling items.

iii. If there is a difference between energy sales and cost of power, please explain why Norfolk Power is making a profit or loss on the commodity.

Response:

There is no difference between the energy sales and cost of power for 2009 and 2010. Norfolk Power is not making a profit or loss on the commodity sale.

c) Regarding the accounting treatment of the IESO Charge Type 146.

i. Does the applicant pro-rate IESO Charge Type 146 Global Adjustment into the RPP portion and non-RPP portion? If not, why not. If so, please provide the supporting spreadsheet for the year 2010 which prorates the IESO Charge Type 146 Global Adjustment into RPP portion and non-RPP portion.

Response:

Yes. Norfolk Power does pro-rate the IESO charge type 146 into RPP and Non-RPP portions. Norfolk uses uplifted sales and AQEW to allocate.

Please see Appendix 9 Charge Type 146 Global Adjustment Board Staff IR 69.

ii. Is the RPP portion included in Account 4705 control account and then incorporated into the variance reported in Account 1588 control account? If not, why not. If so, please provide journal entries for the month of December 2010 to record the RPP portion of global adjustment in Account 4705 control account and incorporated into the variance reported in Account 1588 control account.

Response:

Norfolk Power records all COP expenses in 4705 and uses spreadsheets to separate the COP variance from the Global Adjustment balance. Attached below is the total 1588 COP and the 1588 Global Adjustment sub-account variances.

Please see Appendix 9 Charge Type 146 Global Adjustment Board Staff IR 69.

iii. Is the non-RPP portion included in Account 4705 sub-account Global Adjustment and then incorporated into the variance reported in Account 1588 sub-account Global Adjustment? If not, why not. If so, please provide journal entries for the month of December 2010 to record the non-RPP portion of global adjustment in Account 4705 subaccount Global Adjustment and incorporated into variance reported in Account 1588 sub-account Global Adjustment.

Response:

See response to ii. above.

iv. If any of part "i", "ii", or "iii" above is not followed, please make appropriate adjustments and file the updated evidence. Please provide explanations for the changes made by Norfolk Power, if any.

Response:

Norfolk Power's accounting follows the method communicated by the OEB. The spreadsheets provided in ii. above provide details. No adjustment entries are required.

70. Ref: Exhibit 9/Tab 2/Sch 1/p.7

With regard to 2010 Account 1572 – Extraordinary Event Costs

a) Please provide information supporting the prudency of costs incurred associated with the procurement of external contractors – $140,831 of costs as reported in Exhibit 9/Appendix B, page 1. Please also provide the rationale for procuring most of the work from two contractors, K-Line Construction and Davey Tree Service, and provide support that they are "low-cost" contractors in comparison to competitors.

Response:

Norfolk Power assessed the impact of the wind storm on its distribution system, the number of customers affected by the outage, the conditions during the outage, and the ability of Norfolk Power crews to make the needed repairs within a reasonable time period. Based on this analysis it was deemed necessary to enlist external contractors to assist in repairing the damaged distribution plant and restore power to affected areas. Davey Tree Service was selected for tree trimming on the basis that they were the successful applicant in Norfolk's 2011 tree trimming tendering process. K-Line Construction has regularly performed work for Norfolk for a number of years, successfully bidding in tendering processes for various projects. Based on this, their availability and their familiarity with Norfolk's system, K-Line Construction was selected.

b) Please provide copies of all invoices for the $140,831 of costs included in Appendix B, page 3 – those costs incurred by procuring local LDCs and external contractors.

Response:

Please see Appendix 10 Contractor Invoices April 28, 2011 Wind Storm Board Staff IR 70b for copies of all invoices for the $140,831 of expenses.

c) Please provide the method used to determine the level of incremental labour costs including the method for tracking overtime hours and labour rates.

Response:

Norfolk Power tracks internal labour hours using timesheets and a weekly payroll entry system. Time spent on specific jobs or projects is allocated directly to a work order assigned to that task or project, and then costs based on individual wage rates are charged to the work orders. For the labour hours associated with storm damage repairs for the 2011 wind storm, a special work order was set up to capture all costs associated with the storm. Once all costs had been collected, Norfolk Power transferred the incremental costs (overtime hours only) to Account 1572. Norfolk Power only claimed overtime specifically associated with storm damage repairs. In order to comply with the incremental cost criteria for Z-Factor applications, regular labour hours were deemed non-incremental and not included.

d) Does Norfolk Power have a contingency plan for the provision of emergency response services? If so, please summarize the extent to which Norfolk Power followed its contingency plan.

Response:

Norfolk Power has an Emergency Preparedness Plan that was enacted during the windstorm of April 28, 2011. The plan was followed during the storm. Norfolk Power assigned roles and responsibilities, and enacted the mutual aid provision within the plan. A review of this plan was conducted both internally and in conjunction with Norfolk County's Emergency Plan. Lessons learned for improvement were conducted and incorporated into the plan to improve Norfolk Power's preparedness should the plan have to be implemented in the future.

If Norfolk Power deviated in any material way from the plan, please identify the deviations and the reasons for those deviations. If not, please explain.

Response:

Norfolk Power followed the plan as it was designed.

e) Does Norfolk Power have insurance coverage for storm damages? If so, please provide detailed evidence on the insurance coverage.

Response:

Norfolk Power carries property insurance but it does not cover the transmission and distribution plant for storm damages.

f) Please confirm that Norfolk Power is proposing to recover the storm damage costs over a one-year period through a separate rate rider.

Response:

Norfolk Power confirms that it is proposing to recover the storm damage costs over a one-year period through a separate rate rider.

g) Board staff notes that these costs have not been audited. Please provide reasons why the Board should depart from its general practice of only disposing of deferral and variance account balances that have been audited by an external auditor.

Response:

Norfolk Power reviewed the Z-factor filing guidelines as found in Chapter 3 of the Filing Requirements for Transmission and Distribution Applications, June 22, 2011. This filing guideline referred to section 2.6 of the Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors – July 14, 2008". Section 2.6 states

> "Distributors are expected to report events to the Board promptly and *apply to the Board for any amounts claimed under Z-factor treatment with the next rate application*. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment." (Italics added for emphasis).

Norfolk filed the Z-factor application as directed in this report.

Smart Meters

71. Ref: Exhibit 9/Tab 5/Sch 1

Please confirm that the requested Smart Meter Rate Rider is $1.71 per month per metered customer and not $1.75 per month per metered customer, as shown on line 14 of page 1.

Response:

Norfolk confirms that the requested Smart Meter Rate Rider is $1.71 per month per metered customer. The amount shown on Line 14 of Page 1 of $1.75 was an error.

72. Ref: Exhibit 9/Tab 5/Sch 1

Please rerun and submit a revised version of the Smart Meter Model adjusting for the following two matters:

a) It appears the current (and recent models) calculate compounded interest on funding adder revenues. Please revise the model applying simple interest (i.e. interest on the opening monthly balance of the principal only) on funding adder revenues, and

b) Please revise the model to calculate simple interest expense on the opening monthly balance for OM&A and amortization expenses.

Response:

Norfolk has submitted the latest Smart Meter Model from Board Staff with the responses to these interrogatories. Norfolk requests that the Board accept the updated model as filed and disregard the previous model submitted.

With Norfolk's original application the Smart Meter model calculated a net deferred Revenue Requirement of $730,203. Norfolk has reviewed the expenses claimed and has removed $127,986 as non-incremental OM&A expenses. In addition the use of the new model addresses a compounding interest issue as noted in Board Staff Interrogatory 72. These changes result in a reduced net deferred Revenue Requirement of $397,000. Norfolk requests to recover this amount over a 4 year period through a Smart Meter Disposition Rate Rider of $0.43 per month per metered customer, beginning May 1, 2012.

As per Norfolk’s original application, (Exhibit 9, Tab 5, Schedule 5), Norfolk is still requesting recovery of $857,731 from stranded assets (stranded meters). Based on 19,303 customers and recovery over 4 years the rate rider for the stranded assets amounts to $0.9257 per month, per metered customer.

Norfolk notes the new model appropriately calculates the interest as requested in parts a and b of this interrogatory.

73. Ref: Exhibit 9/Tab 5/Sch 1

Please re-calculate the smart meter disposition rider using the following methodology that is based on the approach approved by the Board in PowerStream's 2010 smart meter application (EB-2010-0209):

a) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model) Allocate the OM&A based on the number of meters installed for each Class Allocate PILs based on the revenue requirement allocated to each class before PILs

b) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes.

c) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement.

d) Allocate the amount calculated in part (c) by using the allocation factors derived in part (b)

e) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (d) by the number of customers in each class, and then divide by 12.

f) If the proposed disposition period is greater than 1 year, divide the result of part (e) by the proposed number of years.

Response:

The smart meter disposition rider using the methodology outlined above is provided in the following table and reflects the updated information provided in the revised smart meter model referenced in response to IR#72.

Smart Meter Actual Cost Recovery Rate Rider Calculated by Rate Class			
	Total	Residential	GS < 50
Allocators			
CWMC (Account 1860)	3,827,123	3,427,572	399,551
CWMC (Account 1860)	100.00%	89.56%	10.44%
Number of meters installed	18,796	16,831	1,965
Number of meters installed	100.00%	89.55%	10.45%
Revenue Requirement Allocation before PILs	9,782,462	7,778,502	2,003,961
Revenue Requirement Allocation before PILs	100.00%	79.51%	20.49%
Total Return (deemed interest plus return on equity)	$ 494,596	$ 442,960	$ 51,636
Amortization	$ 617,674	$ 553,189	$ 64,485
OM&A	$ 264,346	$ 236,710	$ 27,636
PILs	$ 30,270	$ 24,069	$ 6,201
Total Revenue Requirement 2006 to 2011	$ 1,406,885	$ 1,256,928	$ 149,957
	100.00%	89.34%	10.66%
Smart Meter Rate Adder Revenues	($980,975)		
Carrying Charge	($28,910)		
Smart Meter True-up	$ 397,000	$ 354,685	$ 42,316
Metered Customers	19,303	16,831	2,472
Rate Rider to Recover Smart Meter Costs Over 4 Years	$ 0.43	$ 0.44	$ 0.36

74. Ref: Exhibit 9/Tab 2/Sch 1/p.6

a) Please confirm that Norfolk Power's costs recorded in Account 1555 and Account 1556 are directly related to the smart meter program and are incremental costs. If this is not the case, please explain.

Response:

In the time since the original submission of this application, Norfolk conducted a thorough review of all costs included in accounts 1555 and 1556. As a result of this review, Norfolk has removed non-incremental costs of $127,986 that was originally included in Account 1556 (Smart Meter OM&A), mainly internal labour costs. The updated Smart Meter model submitted with these interrogatory responses reflects the removal of those non-incremental OM&A costs from account 1556. As such, Norfolk confirms that the costs recorded in Accounts 1555 and 1556 are directly related to the smart meter program and are incremental costs.

b) Please confirm Norfolk Power's costs recorded in Account 1555 and Account 1556 are in accordance with the Board's August 7, 2007 Decision in the combined proceeding regarding smart meters (EB-2007-0063) (the "Combined Smart Meter Proceeding"), Appendix A.

Response:

Norfolk confirms that the costs recorded in Account 1555 and 1556 are in accordance with the Board's August 7, 2007 Decision in the combined proceeding regarding smart meters (EB-2007-0063) (the "Combined Smart Meter Proceeding"), Appendix A.

c) Do the costs recorded in Account 1555 meet the 14 categories of eligible capital cost components (Appendix A to the Board's August 7, 2007 Decision) listed below?

Advance Metering Communication Device (AMCD)

1. Smart Meter
2. Installation Cost
3. Workforce Automation

Advanced Metering Regional Collector (AMRC) (includes LAN)
4. Collectors
5. Repeaters
6. Installation

Advanced Metering Control Computer (AMCC)

7. Computer Hardware
8. Computer Software
9. Computer Software Licence & Installation

Wide Area Network (WAN)
10. Activation Fees

Other AMI Capital Costs related to Minimum Functionality
11. AMI Interface to CIS
12. Professional Fees
13. Integration
14. Program Management

Response:

Norfolk's costs meet the 14 categories of eligible capital cost components listed above. Norfolk has filed the updated Smart Meter Model issued by the Board with these interrogatory responses. This model provides the details of the costs for each of the applicable capital cost components listed above.

d) Do the costs recorded in Account 1556 meet the certain OM&A expenses identified by the Board as eligible costs? These costs (Appendix A to the Board's August 7, 2007 Decision) are listed below.

AMCD Maintenance
AMRC/LAN Maintenance
AMCC Hardware and Software Maintenance
WAN
Other (Business Process Redesign/Customer Communication/Program Management/Change Management)

Response:

Norfolk confirms that the costs recorded in Account 1556 meet the certain OM&A expenses identified by the Board as eligible costs (listed above).

75. Ref: Exhibit 9/Tab 2/Sch 1/p.6

a) Please confirm that Norfolk Power does not include borrowing costs relating to money borrowed to finance smart meter installations, if any, as part of the Smart Meter Capital Account 1555 or Account 1556. Please identify, if any, which USoA account Norfolk Power uses to record the borrowing costs.

Response:

Norfolk confirms that it does not include borrowing costs relating to money borrowed to finance smart meter installations as part of the Smart Meter Capital Account 1555 or Account 1556.

b) With regard to the Board's Guideline: "Smart Meter Funding and Cost Recovery" (G-2008-0002) (the "Guideline") issued on October 22, 2008, does Norfolk Power use its normal capitalization policy for smart meters? If this is not the case, please provide an explanation.

Response:

Norfolk did use its normal capitalization policy for Smart Meters. Typically, burdened overhead is not applied to meters, and in the case Smart Meters, Norfolk did not apply burdens to its meters.

c) Is Norfolk Power recording Stranded Meter Costs in "Subaccount Stranded Meter Costs" of Account 1555, or fixed assets (i.e., Account 1860, Meters), or both? How does Norfolk Power ensure that the same stranded meter assets are not recorded in both Account 1555 and Account 1860 (i.e. avoid double counting)?

Response:

Norfolk is recording Stranded Meter Costs in fixed assets (Account 1860) until January 1, 2012 at which time it will transfer the gross fixed asset costs and accumulated depreciation of the Stranded Assets to the approved sub-account of 1555 (at the same time, Norfolk will transfer the capital costs and accumulated amortization from Account 1555 relating to Smart Meters to a sub-account of 1860 – Meter Capital). By maintaining the integrity of the asset values and related accumulated depreciation of the Stranded Meters in 1860 until Smart Meters are approved in Rate Base (assuming January 1, 2012), Norfolk ensures that the same stranded meter assets are not recorded in both Account 1555 and Account 1860.

d) Are the stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation and less any proceeds from the disposition of the meters?

Response:

The stranded meter costs recorded in (currently Account 1860, to be transferred to Account 1555) are comprised of the gross costs of the stranded meters, less the accumulated depreciation and less any proceeds from the disposition of the meters. Norfolk does not and has not collected capital contributions for meters, and as such, no portion of capital contributions is related to the stranded meter amount.

76. Ref: Exhibit 9/Tab 7/Sch 1

Regarding Table 7.1, how was the Return on Rate Base amount of $12,542 derived?

Response:

Regarding Table 7.1, the Return on Rate Base amount of $12,542 was derived using the methodology as prescribed by the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (EB-2008-0408) dated June 13, 2011. Details of the calculation have been provided below.

This Data Is Provided in Table 1.6 in Exhibit 2/Tab 1/Schedule 2 for 2012 CGAAP Test Year

	December 31, 2011 CGAAP	December 31, 2011 IFRS	DIFFERENCE (book to PPE Variance Account)
Gross Fixed Assets	79,147,237	52,667,450	
Accumulated Depreciation	28,808,038	1,970,919	
Net Book Value	**50,339,199**	**50,696,531**	**357,332**

Average Balance in PPE Variance Account = Difference between IFRS & CGAAP / 2
= **$178,666**

Interest on Average Balance in PPE Variance Account = 7.02% X $178,666
= **$12,542**

The 7.02% is the same return Norfolk has used in determining revenue requirement. Details of Norfolk's cost of capital can be found at Exhibit 5/Tab 1/Schedule 2/Table 1.1.

APPENDIX 1 – BOARD STAFF INTERROGATORIES

Fixed Asset Continuity Schedule

BS IR#10e)

BOARD STAFF #10(e)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **Actual 2010**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals / Adjustments	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals / Adjustments	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ -		$ 302,784	$ -	$ -		$ -	$ 302,784
47	1808	Buildings	2.00%	$ 1,615,717	$ 4,361		$ 1,620,078	-$ 149,866	-$ 32,358	$ 1,648	-$ 180,575	$ 1,439,503
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 3,215,596	$ 5,696,787		$ 8,912,383	-$ 377,926	-$ 151,636	$ 5,176	-$ 524,387	$ 8,387,996
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 4,120,928	$ 33,675	-$ 1,386,755	$ 2,767,848	-$ 1,691,662	-$ 87,303	$ 1,415,631	-$ 363,334	$ 2,404,514
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 25,698,012	$ 846,036	-$ 5,686,690	$ 20,857,358	-$ 12,098,600	-$ 848,278	$ 5,748,601	-$ 7,198,276	$ 13,659,082
47	1835	Overhead Conductors & Devices	4.00%	$ 13,715,614	$ 751,468	-$ 2,750,300	$ 11,716,783	-$ 5,405,305	-$ 453,642	$ 2,802,934	-$ 3,056,012	$ 8,660,771
47	1840	Underground Conduit	4.00%	$ 3,845,066	$ 160,329		$ 4,005,396	-$ 1,373,797	-$ 139,617	$ 11,576	-$ 1,501,837	$ 2,503,558
47	1845	Underground Conductors & Devices	4.00%	$ 7,636,026	$ 255,331	-$ 1,204,925	$ 6,686,432	-$ 2,729,642	-$ 262,351	$ 1,228,921	-$ 1,763,071	$ 4,923,361
47	1850	Line Transformers	4.00%	$ 11,237,917	$ 744,525		$ 11,982,442	-$ 6,212,344	-$ 542,264	$ 44,045	-$ 6,710,564	$ 5,271,877
47	1855	Services (Overhead & Underground)	4.00%	$ 2,507,308	$ 271,077		$ 2,778,385	-$ 432,561	-$ 105,714	$ 17,900	-$ 520,375	$ 2,258,010
47	1860	Meters	4.00%	$ 4,025,165	$ 131,968		$ 4,157,133	-$ 2,229,621	-$ 155,695	$ 10,181	-$ 2,375,136	$ 1,781,996
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,215,638	$ 91,650		$ 2,307,288	-$ 810,205	-$ 33,216	$ 2,679	-$ 840,742	$ 1,466,546
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,223	-$ 640		-$ 3,863	$ 2,314
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 411,687	$ 5,958	-$ 264,715	$ 152,930	-$ 345,971	-$ 15,028	$ 266,478	-$ 94,521	$ 58,409
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 1,280,299	$ 44,046	-$ 609,419	$ 714,926	-$ 1,089,266	-$ 103,294	$ 636,791	-$ 555,770	$ 159,156
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 406,997	$ 35,884	-$ 147,109	$ 295,773	-$ 284,676	-$ 44,571	$ 156,246	-$ 173,001	$ 122,771
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 2,122,603	$ 75,784	-$ 659,750	$ 1,538,637	-$ 1,510,404	-$ 170,213	$ 618,087	-$ 1,062,530	$ 476,107
8	1935	Stores Equipment	10.00%	$ 120,335	$ 358	-$ 81,132	$ 39,562	-$ 102,515	-$ 3,938	$ 81,339	-$ 25,115	$ 14,447
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 727,933	$ 6,946	-$ 417,155	$ 317,724	-$ 573,406	-$ 31,425	$ 420,526	-$ 184,305	$ 133,419
8	1945	Measurement & Testing Equipment	10.00%	$ 178,973	$ 1,895		$ 180,868	-$ 93,994	-$ 17,992	$ 1,672	-$ 110,314	$ 70,554
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 106,906	$ 1,021		$ 107,927	-$ 47,912	-$ 10,742	$ 2,599	-$ 56,055	$ 51,872
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 412,334	$ 15,885		$ 428,220	-$ 100,640	-$ 42,028	$ 13,640	-$ 129,028	$ 299,192
47	1975	Load Management Controls Utility Premises	N/A	$ 16,565	$ -	-$ 16,565	$ -	-$ 16,565	-$ -	$ 16,565	$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 613,956	$ 540,685		$ 1,154,641	-$ 266,709	-$ 58,953	$ 64	-$ 325,599	$ 829,042
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 12,653	$ 9,479		$ 22,132	-$ 4,522	-$ 3,478	$ 1,265	-$ 6,735	$ 15,397
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 7,654,021	-$ 819,501		-$ 8,473,522	$ 1,638,433	$ 322,553	-$ 29,144	$ 1,931,842	-$ 6,541,679
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 5,019	-$ 1,004		-$ 6,023	$ 4,015
N/A	2055	Work In Progress	N/A	$ 5,472,038	-$ 5,472,038		$ -	$ -	$ -		$ -	$ -
		Total		**$ 85,016,144**	**$ 3,433,607**	**-$ 13,224,513**	**$ 75,225,237**	**-$ 36,317,916**	**-$ 2,992,829**	**$ 13,475,419**	**-$ 25,835,326**	**$ 49,389,911**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 170,213
Stores & Garage Equipment	-$ 33,317
Computer HW & SW	-$ 147,866
Adjustment for 1/2 Year Rule	-$ 289,866
Net Depreciation to Inc. Stmt	**-$ 2,351,567**

Note: 2010 Amortization Expense adjusted for 2007 to 2009 cumulative effect of adopting half-year rule

BOARD STAFF #10(e)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011 Bridge** **IFRS** *REVISED TO SHOW FULL GROSS ASSET & ACCUMULATED DEPRECIATION*

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 180,575	-$ 33,112		-$ 213,687	$ 1,406,391
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 524,387	-$ 232,330		-$ 756,717	$ 8,155,666
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,767,848	$ 65,131		$ 2,832,979	-$ 363,334	-$ 161,059		-$ 524,393	$ 2,308,586
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 20,857,358	$ 1,038,945		$ 21,896,303	-$ 7,198,276	-$ 395,240		-$ 7,593,517	$ 14,302,786
47	1835	Overhead Conductors & Devices	4.00%	$ 11,716,783	$ 738,072		$ 12,454,855	-$ 3,056,012	-$ 191,773		-$ 3,247,785	$ 9,207,070
47	1840	Underground Conduit	4.00%	$ 4,005,396	$ 191,050		$ 4,196,446	-$ 1,501,837	-$ 60,211		-$ 1,562,048	$ 2,634,397
47	1845	Underground Conductors & Devices	4.00%	$ 6,686,432	$ 336,943		$ 7,023,375	-$ 1,763,071	-$ 219,158		-$ 1,982,229	$ 5,041,146
47	1850	Line Transformers	4.00%	$ 11,982,442	$ 784,127		$ 12,766,569	-$ 6,710,564	-$ 174,804		-$ 6,885,368	$ 5,881,200
47	1855	Services (Overhead & Underground)	4.00%	$ 2,778,385	$ 232,828		$ 3,011,213	-$ 520,375	-$ 66,958		-$ 587,333	$ 2,423,880
47	1860	Meters	4.00%	$ 4,157,133	$ 62,526		$ 4,219,659	-$ 2,375,136	-$ 97,707		-$ 2,472,843	$ 1,746,815
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,307,288	$ 10,000		$ 2,317,288	-$ 840,742	-$ 101,372		-$ 942,114	$ 1,375,174
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,863	-$ 654		-$ 4,517	$ 1,660
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 152,930	$ 15,000		$ 167,930	-$ 94,521	-$ 15,568		-$ 110,089	$ 57,841
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 714,926	$ 30,000		$ 744,926	-$ 555,770	-$ 63,095		-$ 618,865	$ 126,061
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 295,773	$ 27,000		$ 322,773	-$ 173,001	-$ 37,574		-$ 210,575	$ 112,197
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 1,538,637	$ 440,000		$ 1,978,637	-$ 1,062,530	-$ 82,451		-$ 1,144,981	$ 833,656
8	1935	Stores Equipment	10.00%	$ 39,562	$ -		$ 39,562	-$ 25,115	-$ 3,990		-$ 29,105	$ 10,457
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 317,724	$ 35,000		$ 352,724	-$ 184,305	-$ 32,269		-$ 216,574	$ 136,150
8	1945	Measurement & Testing Equipment	10.00%	$ 180,868	$ -	-$ 42,514	$ 138,354	-$ 110,314	-$ 12,762		-$ 123,076	$ 15,278
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 107,927	$ 8,000	-$ 13,133	$ 102,794	-$ 56,055	-$ 23,866		-$ 79,921	$ 22,873
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 428,220	$ -	-$ 33,857	$ 394,363	-$ 129,028	-$ 99,699		-$ 228,727	$ 165,636
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,154,641	$ 212,761		$ 1,367,402	-$ 325,599	-$ 57,234		-$ 382,833	$ 984,569
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 6,735	-$ 847		-$ 7,582	$ 14,550
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 8,473,522	-$ 861,340		-$ 9,334,862	$ 1,931,842	$ 193,818		$ 2,125,660	-$ 7,209,201
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 6,023	-$ 1,004		-$ 7,027	$ 3,011
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 75,225,237	$ 3,367,043	-$ 89,504	$ 78,502,776	-$ 25,835,326	-$ 1,970,919	$ -	-$ 27,806,246	$ 50,696,531

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 82,451
Stores & Garage Equipment	-$ 37,263
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	-$ 1,851,205

BOARD STAFF #10(e)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012 Test** **IFRS** *REVISED TO SHOW FULL GROSS ASSET & ACCUMULATED DEPRECIATION*

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance (Adjusted for Smart Meters & Stranded Meters)**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance (Adjusted for Smart Meters & Stranded Meters)**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 213,687	-$ 33,112		-$ 246,799	$ 1,373,279
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 756,717	-$ 232,330		-$ 989,047	$ 7,923,336
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,832,979	$ 245,564		$ 3,078,543	-$ 524,393	-$ 167,198		-$ 691,591	$ 2,386,952
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 21,896,303	$ 1,306,399		$ 23,202,702	-$ 7,593,517	-$ 421,300		-$ 8,014,817	$ 15,187,885
47	1835	Overhead Conductors & Devices	4.00%	$ 12,454,855	$ 825,987		$ 13,280,842	-$ 3,247,785	-$ 199,428		-$ 3,447,213	$ 9,833,629
47	1840	Underground Conduit	4.00%	$ 4,196,446	$ 89,296		$ 4,285,742	-$ 1,562,048	-$ 63,015		-$ 1,625,063	$ 2,660,678
47	1845	Underground Conductors & Devices	4.00%	$ 7,023,375	$ 181,271		$ 7,204,646	-$ 1,982,229	-$ 227,795		-$ 2,210,024	$ 4,994,622
47	1850	Line Transformers	4.00%	$ 12,766,569	$ 850,097		$ 13,616,666	-$ 6,885,368	-$ 195,231		-$ 7,080,599	$ 6,536,066
47	1855	Services (Overhead & Underground)	4.00%	$ 3,011,213	$ 334,860		$ 3,346,073	-$ 587,333	-$ 74,055		-$ 661,388	$ 2,684,685
47	1860	Meters	4.00%	$ 2,087,050	$ 310,750		$ 2,397,800	-$ 1,200,905	-$ 50,876		-$ 1,251,781	$ 1,146,018
47	1860	Meters (Smart Meters)	10.00%	$ 3,214,012	$ -		$ 3,214,012	-$ 479,090	-$ 321,401		-$ 800,491	$ 2,413,521
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,317,288	$ -		$ 2,317,288	-$ 942,114	-$ 101,472		-$ 1,043,586	$ 1,273,702
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 4,517	-$ 654		-$ 5,171	$ 1,006
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 167,930	$ 15,500		$ 183,430	-$ 110,089	-$ 13,790		-$ 123,879	$ 59,551
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 744,926	$ 40,000		$ 784,926	-$ 618,865	-$ 93,720		-$ 712,585	$ 72,341
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 322,773	$ 142,500		$ 465,273	-$ 210,575	-$ 47,211		-$ 257,786	$ 207,486
12	1925	Computer Software (Smart Meters)	25.00%	$ 406,373	$ -		$ 406,373	-$ 129,885	-$ 101,593		-$ 231,478	$ 174,895
10	1930	Transportation Equipment	10% to 25%	$ 1,978,637	$ 40,000		$ 2,018,637	-$ 1,144,981	-$ 98,451		-$ 1,243,432	$ 775,205
8	1935	Stores Equipment	10.00%	$ 39,562	$ -		$ 39,562	-$ 29,105	-$ 3,107		-$ 32,212	$ 7,350
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 352,724	$ 28,000		$ 380,724	-$ 216,574	-$ 30,959		-$ 247,533	$ 133,191
8	1945	Measurement & Testing Equipment	10.00%	$ 138,354	$ -		$ 138,354	-$ 123,076	-$ 9,772		-$ 132,848	$ 5,506
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 102,794	$ 53,000		$ 155,794	-$ 79,921	-$ 22,089		-$ 102,010	$ 53,784
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 394,363	$ -		$ 394,363	-$ 228,727	-$ 88,879		-$ 317,606	$ 76,757
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,367,402	$ 89,296		$ 1,456,698	-$ 382,833	-$ 64,785		-$ 447,618	$ 1,009,080
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 7,582	-$ 847		-$ 8,429	$ 13,703
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 9,334,862	-$ 652,000		-$ 9,986,862	$ 2,125,660	$ 205,507		$ 2,331,167	-$ 7,655,694
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 7,027	-$ 1,004		-$ 8,031	$ 2,007
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 79,990,552**	**$ 3,900,520**	**$ -**	**$ 83,891,072**	**-$ 27,143,283**	**-$ 2,458,567**	**$ -**	**-$ 29,601,850**	**$ 54,289,222**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 98,451
Stores & Garage Equipment	-$ 32,591
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 2,327,525**

APPENDIX 2 – BOARD STAFF INTERROGATORIES

External Review IFRS

BS IR#11b)

KPMG LLP
Chartered Accountants
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Mr. Jody McEachran
Chief Financial Officer
Norfolk Power Distribution Inc.
P.O. Box 588
70 Victoria Street
Simcoe ON N3Y 4N6

November 23, 2011

Dear Mr. McEachran:

IFRS Accounting Policies

We are writing this letter to describe the nature of our assistance to Norfolk Power Distribution Inc. ("the Company") in its effort to develop IFRS compliant accounting policies. We provided our services through a series of facilitated sessions to assist management of the Company in its development of its IFRS compliant accounting policies. This facilitation process has been used in our work with 18 other utilities assisting them with their conversion to IFRS. A member of our team also worked with the Ontario Energy Board (the "OEB") to develop the Board report on the Transition to International Financial Reporting Standards.

We facilitated a session with management and engineering/operations staff to assist them with the determination of the level of componentization required by IFRS. Once the IFRS compliant components were determined by management, we facilitated a session with management and engineering/operations staff to determine the useful lives of the components based upon the definition of useful life contained in IAS 16. As instructed by the Ontario Energy Board ("OEB"), the Company made use of the Kinectrics Report commissioned by the OEB "to assist the distributors in their transition from Canadian Generally Accepted Accounting Principles … to these international standards."[1] , the facilitated session was used by management of the Company to consider the information in the Kinectrics Report to develop the asset service lives suitable in the Company's circumstances as advised by the OEB and outlined in it's letter to All Licensed Distributors dated July 8, 2010.

[1] Ontario Energy Board, Letter to All Licensed Electricity Distributors dated July 8, 2010

KPMG

We facilitated a session with management to review the costs included in the Company's burden rates used to capitalize overhead costs to the construction of its assets. The costs were reviewed by management to determine whether they were "costs that were directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management."[2] Costs were also reviewed by management for any costs specifically excluded from the definition of the elements of cost in IAS 16.19. Management discussed and determined an appropriate definition of administration and other general overhead costs in relation to the costs included in the Company's CGAAP burden costs.

We facilitated a session with management in order for management to determine the Company's definition of a "Qualifying Asset" in accordance with IAS 23, specifically, to define the period of time that is "a substantial period of time to get ready for its intended use or sale."[3]

At the conclusion of the facilitated sessions, we assisted with the drafting of management's accounting policy documents based upon the decisions and conclusions made by management during the facilitated sessions.

Yours very truly

Lois Ouellette, CA
Senior Manager
905-687-3276

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[2] IAS 16.16(b)
[3] IAS 23.5

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

November 25, 2011

Norfolk Power Distribution Inc.
70 Victoria Street
Simcoe, Ontario
N3Y 4N6

Attention: Mr. Brad Randall, President & CEO

Re: IFRS 1 – Elective Exemption
IAS 16 – Property, Plant and Equipment
IAS 23 – Borrowing Costs

We have reviewed Norfolk Power Distribution Inc.'s proposed policies and these proposed policies are consistent with the International Financial Reporting Standards disclosed above.

If you wish to discuss this further please feel free to contact me at your convenience.

Yours truly,
Millard, Rouse & Rosebrugh LLP

Jeff O'Donnell, CA, Partner

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APPENDIX 3 – BOARD STAFF INTERROGATORIES

Conclusion Document IAS 16 – PPE Burdens

BS IR#11c)

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy on the capitalization of burdens.

Background:

Core Principle

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and other general overhead costs; and,
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly attributable

The term "directly attributable" is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

General and administrative overhead

IFRS does not provide a definition of general and administrative overhead (G&A). The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

Day-to-day servicing costs

Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E. Day-to-day servicing costs related to an item of PP&E are not included in the cost of that item of PP&E.

Feasibility studies and pre-construction activities

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

Considerations:

Canadian GAAP allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Under IFRS, training costs and repairs and maintenance cannot be capitalized. Training on how to use a piece of equipment can be capitalized, but actual training on a piece of equipment cannot be capitalized. Repairs and maintenance costs of an item of PP&E cannot be capitalized to the cost of that item of PP&E. Under IFRS, short term benefits are allowed to be capitalized.

NP includes certain burdens in the cost of its constructed assets using the following burdens:

- Payroll
- Fleet maintenance
- Stores
- Engineering

Payroll

IAS 16 specifically allows for the cost of employee benefits as defined in IAS 19 to be capitalized as a directly attributable cost. The payroll expenses included in the payroll burden, therefore, can be capitalized except for training costs and repairs and maintenance.

NP includes training costs in the burdens which cannot be capitalized under IFRS. The following are the training costs that cannot be capitalized under IFRS:

- In-house training (a/c 90910) - These are miscellaneous expenses and therefore are not directly attributable.
- Miscellaneous courses and workshop (a/c 90918) – These expenses are miscellaneous expenses and not directly attributable.
- Safety consulting (a/c 90920) – These expenses are training costs and not capitalizable.
- EUSA (a/c 90921) – This expense includes safety training and training expenses for licenses which are required for employees in order for employees to install certain assets. Training costs are specifically excluded from capitalization under IFRS.
- Safety meetings and training (a/c 90930) – This expense mostly includes employee time to attend safety meetings. This is not directly attributable to an asset and therefore cannot be capitalized.
- Trade show attendance (a/c 90931) – These expenses are not directly attributable to an asset and therefore cannot be capitalized.

Fleet Maintenance

Timesheets are completed for the time that a truck is on a job site and therefore use of the truck can be directly attributed to an item of PP&E. Fleet maintenance costs are charged to capital based upon an hourly rate for the time spent on the job site. The following costs are included in the determination of the hourly rate.

Labour and Parts expenses included in this account are related to repair work on the vehicle which is used to construct an item of PP&E and are therefore capitalized.

Depreciation, fuel and other expenses (including inspection, lease costs and plate renewal) can be capitalized as they can be directly related to the construction of an asset.

Repairs and maintenance expenses are not permitted to be capitalized to the cost of the truck as they are day to day servicing costs which are not capitalizable. Repairs and maintenance of the vehicles used in construction of PP&E are costs of operating the vehicle just like oil and gas. As such, they are part of the cost of using the vehicles for constructing PP&E and should therefore be capitalized.

Truck stand-by is a default account that is used when a truck is not in use. These expenses should not be capitalized as they are not directly attributable to an item of PP&E. Similarly, truck downtime cannot be included and must be expensed.

Insurance expense can be capitalized as it is part of the cost of operating the truck while the truck is used to construct an asset and so it is directly attributable to an asset.

Staff time to deliver vehicles to the repair facility cannot be capitalized as it is not attributable to a specific item of PP&E. Staff time spent on truck washing and miscellaneous repair are part of the operating costs of the vehicles used in the construction of PP&E and therefore are capitalized.

Stores and Engineering

Store Activities

Included in this expense are labour hours, trucking, accounts payable and property charges. Labour hours included are for the stockkeeper, some of the purchasing manager’s hours and a part-time employee’s hours. The labour for the stock keeper is directly attributable to an asset as it relates to inventory, which is going to specific capital jobs.

Most of the purchasing manager's job is related to request for proposals and receiving of inventory. Since requests for proposal are for specific jobs, this time is directly attributable to an item of PP&E. Time spent receiving the inventory is not considered to be directly attributable to a specific item of PP&E and is not capitalized.

The part-time employee spends the majority of his time performing building maintenance and cleaning work. This is not considered to be directly attributable to an item of PP&E and so is not capitalized in the burden.

As property charges will occur regardless of the amount of inventory held and is not incurred for the purpose of constructing an item of PP&E, it is not to be included.

IT expenses are more of a general and administrative nature as they would occur regardless of whether any assets are constructed. There is an exception for IT expenses being allocated to engineering, since IT assets are used for specific jobs.

Conclusion:

Labour costs relating to the part-time employee and some of the purchasing manager's time are to be excluded from the stores burden. Property charges and IT expenses are not to be included.

Engineering:

The following expenses are included in engineering labour; engineering manager, engineering clerk and technicians, drafting services, layouts, underground subdivision, MS/DS Design, miscellaneous engineering expense, technical customer relations, OH and UG line design.

The engineering manager's time is related to engineering design, compliance with regulatory work, management of the technicians, approving the designs and developing the capital budget. Most of the manager's time is capital but some supervision aspects are included. Therefore, expense are to be included as they are directly attributable to the construction of the asset.

The engineering clerk provides support to the technicians which would be considered administrative support. These hours are not directly attributable to specific capital projects and therefore this expense is not be capitalized.

The technicians work on specific capital projects and therefore should be capitalized as they are directly attributable costs.

Drafting services and layouts are directly related to the design of capital projects (assets). Therefore, these costs should be capitalized.

Underground subdivision costs are directly related to construction of underground assets and therefore capitalized.

MS/DS Design costs are directly related to the design of specific capital assets and therefore should be capitalized.

Miscellaneous engineering expenses (a/c 9100192) are directly attributable to capital as the costs included in this account are incurred by engineering staff as they complete their tasks which are directly attributable to capital projects.

Technical customer relations expenses are directly related to capital projects and therefore capitalized.

O/H and U/G line design expenses are directly related to the design of capital assets and therefore are capitalized.

The entire engineering burden is allocated to capital based on a percentage of the cost of a project (project cost includes materials, labour and trucking).

Conclusion:

NPDI will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates, such as training and other administrative expenses, will not be capitalized.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

Payroll

Training costs and safety meetings were removed from this burden.

Fleet maintenance

Truck stand-by and downtime costs have been removed from this burden.

Stores

Labour costs relating to a part-time employee linked to the department have been removed from this burden. A portion of the purchasing manager's time has been excluded from the burden. Property charges and IT costs have been removed from this burden.

Engineering

Labour costs relating to the engineering clerk have been removed from this burden.

APPENDIX 4 – BOARD STAFF INTERROGATORIES

Borrowing Costs

BS IR#11g)

Conclusion Document

Standard: IAS 23 – Borrowing Costs

Topic: Borrowing Costs – Property, Plant and Equipment

Objective:

To determine the policy on accounting for borrowing costs for property, plant and equipment.

Background:

Borrowing costs are interest and other costs that an entity incurs in connection with the borrowing of funds. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in the IAS standard. Guidance provided by KPMG suggests that a substantial period of time would be considered to be a period well in excess of 6 months.

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E. Norfolk Power has chosen to use the cost model in accordance with the OEB requirement.

IAS 23 requires borrowing costs to be expensed as they are incurred unless they relate to “qualifying assets”, in which case they must be capitalized if certain conditions are met. When interest is capitalized, IAS 23 requires the following steps:

- Begin capitalization when borrowing costs are incurred and expenditures and activities to develop a qualifying asset are in progress;
- Suspend capitalization when development is interrupted for extended periods; and
- Cease capitalization when a qualifying asset is ready for its intended use or sale.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as interest expense.

The borrowing costs capitalized must reflect the weighted average of the actual borrowing costs incurred. The OEB requires the actual interest rate on the debt to be used if the related debt was acquired on an arm’s length basis. If the debt is acquired on a non-arm’s length basis then the interest rate used cannot exceed the Board’s published rates for CWIP.

Definitions:

Qualifying Asset - Management discussed the nature of the projects and typical construction times and determined that NP will work with a definition of “substantial period of time” as being greater than one year to construct.

Based on the projects forecasted, management estimated that the majority of the projects will not take more than 6 months to complete.

Currently, all of the debt held by Norfolk Power is external. Therefore, Norfolk Power would have interest to capitalize to projects potentially greater than 6 months:

Simcoe conversion – management estimates that this project could take the following amount of time:

- 1-2 months design
- 4 months construction

In total this project shouldn't take more than 6 months to complete.

Green energy – FIT connection – It is estimated by management that these projects will take greater than 6 months to complete with expected delays. These delays are not considered to be typical therefore these projects are not qualifying assets. It is anticipated that the majority of the project will not be financed.

It is common practice for Norfolk Power to have delays during projects which are not typical. The business is a constant rolling amount of projects which includes a broad range of jobs; some of which take longer than others. If one job is delayed another is worked on it its place. As a result, some projects will actually take longer than 6 months to construct when delays are factored in. Management concluded that delay time should not be considered when determining if a project is a qualifying asset.

Typically the construction of projects at NP do not take more than 6 months to complete. To determine if borrowing costs need to be capitalized, NP will make it a year end process to assess how long a project has been in progress, and capitalize borrowing costs if a significant period of time has passed for the construction of the asset.

Conclusion:
Norfolk Power concludes that none of the forecasted projects are expected to take greater than 6 months to complete Therefore, none of the projects are considered qualifying assets and none of the associated borrowing costs will be capitalized.

APPENDIX 5 – BOARD STAFF INTERROGATORIES

Asset Retirement Obligations

BS IR#13, 13c)

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment Derecognition of PP&E

Objective:

To document the accounting policy on derecognition of property, plant and equipment.

Background:

The carrying amount of an item of property, plant and equipment (PP&E) shall be derecognized:

(a) On disposal; or

(b) When no future economic benefits are expected from its use or disposal (eg. the item is removed from use).

When a part of an item of PP&E is replaced and that replacement is capitalized under the recognition principle in IAS 16, then the replaced part is derecognized regardless of whether the replaced part has been identified as a separate component and depreciated separately.

The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized. Gains shall not be classified as revenue, but instead should be presented as other income or expense.

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale, by entering into a finance lease, by donation, etc.). In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognizing revenue from the sale of goods. Under IAS 18.14, revenue from the sale of goods shall be recognized when all the following conditions have been satisfied:

(a) The entity has transferred to the buyer the significant risks and rewards of ownership of the goods

(b) The entity retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;

(c) The amount of revenue can be measured reliably;

(d) It is probable that the economic benefits associated with the transition will flow to the entity; and

(e) The costs incurred or to be incurred in respect of the transactions can be measured reliably.

The gain or loss arising from derecognizing an item of PP&E shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Considerations:

The pooled method of accounting for capital assets for Utility companies is a method that is approved by the Ontario Energy Board ("OEB").

The pooled method of accounting, pools like assets together based on the year of addition. The pooling method assumes that each asset will last, on average, their full useful life.

Under the pooled method it is assumed that some assets within the same asset pool may last longer or shorter than their estimated useful lives. It is further assumed that the differences should average out in the long run. However, the assumption does not always hold true, especially when assets are removed from service before the end of their useful lives (e.g., when a road is widened).

Under the pooled method, if an asset is removed from service prior to the end of its useful life, there is no entry to remove the asset as it remains in the General Ledger (i.e. it is not derecognized).

Currently, Norfolk records its capital assets using the pooling method of accounting and does not derecognize assets removed from service prior to the end of their useful lives.

Since Norfolk does occasionally remove assets from service prior to the end of their useful lives, these removed assets should be derecognized. Norfolk must derecognize the cost of the asset being removed/disposed. A write-off should be recorded in for the remaining NBV of the asset removed/disposed. Any proceeds on the disposal of the asset would offset the write-off.

Accounting staff should be notified when assets are removed from service. Accounting staff would then prepare the correct entries to write off said assets.

For the purpose of the rate application, Norfolk will need to determine which assets will be removed before the end of their useful lives in the forecast period so that the NBV's can be written off accordingly.

To determine if a write-off of assets is required, an analysis of each of the projects currently forecasted is set out below.

If these projects include only the addition of a new asset, without removal of old assets, then there are no de-recognition losses to record.

Norfolk Management has reviewed all upcoming/forecasted projects where assets are being removed from service. In each case the assets have been in service for greater than 25 years and as such are fully depreciated. Therefore, the NBV is zero and there will be no loss on disposal.

Projects forecasted:

Simcoe and Waterford conversion projects - These projects involve the removal of existing assets and are being replaced with upgraded assets. These assets are more than 25 years old with NBV's of zero. Therefore there is no loss on disposal to recognize.

Pole replacement program – this program is completed on a systematic basis and management estimates that all poles are at least 25 years old and therefore NBV is zero.

Miscellaneous overhead and underground betterments – these projects are initiated by customer demand requiring the installation of new assets. No assets are removed from service.

Plant relocation road widening – this project involves the removal of some assets which could have a remaining NBV. This is not expected to be significant.

Rebuild Potts Road – Rebuild of pole line since assets are approaching the end of their useful lives. Therefore no loss on disposal to record.

Fleet replacement plan – Norfolk estimates that its existing fleet will not be replaced, but simply added to. In the past, Norfolk has removed vehicles from their records when they are disposed of and therefore they are currently following the rules of IFRS. No change is required.

Miscellaneous DS Equipment Upgrades – This project is for upgrades determined through inspections. Not many assets will be removed as part of this project. Therefore no loss on disposal will occur.

Reroute NP5 F4 to Queen Street South – Management has concluded that the assets to be removed are likely greater than 25 years old, and therefore NBV is zero and no loss on disposal will occur.

NP8 DS Ann Street transformer replacement – this project involves the removal of assets. Management has concluded that the assets to be removed are greater than 25 years old, and therefore NBV is zero and no loss on disposal will occur.

Green energy projects – These are new assets and therefore no assets are being disposed.

Conclusion: None of the projects forecasted for 2012 will result in a loss on disposal of assets.

Conclusion:

No derecongition of costs have been highlighted in the forecasted projects.

In order to be IFRS compliant, Norfolk's Accounting Department needs to be notified when changes occur in the field regarding fixed assets and their removal from service. Accounting must then remove the fixed assets from their records and record the loss in the income statement.

APPENDIX 6 – BOARD STAFF INTERROGATORIES

Depreciation – Amortization Policy BS IR#19b)

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment.

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PP&E to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted for under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

Overhead system

Four components identified – poles, primary conductor, switches and transformers. Cross arms and insulators are attached to the poles but are replaced when the pole is replaced. The life of these fixtures is limited by the life of the pole as a result of this replacement practice. Insulators may be replaced prior to the pole replacement however they are not a significant portion of the cost of a fully dressed pole. For this reason, poles will be grouped with cross arms and insulators. Conductor and switches are grouped under CGAAP, however, the cost relative to each other is significant and the useful lives differ. Conductors and switches will be segregated as separate components. Transformers and voltage regulators are part of the overhead system. There are very few voltage regulators in the system. The useful life of the transformers is comparable to the overhead switches. Since there are so few voltage regulators in the system they will be grouped with transformers. Transformers could be grouped with switches but since they are currently segregated, this segregation will be maintained.

Poles

The poles are wood or concrete, but most poles in the system are wood. Kinectrics identifies the typical useful life of a wood pole as 45 years. Kinectrics typical useful life is based upon high mechanical stress, low electrical load and moderate environmental factors. Mechanical stress impact on poles in Norfolk's system is typical and the amount of stress should be fairly similar amongst Ontario Utilities. Norfolk is impacted a bit more by environmental factors due to the proximity to the lake and being in rural areas (etc). This includes ice storms which also impact their mechanical stress due to the environment in the area. Since there are no indicators that are different than Kinectrics typical situation for the poles, a useful life of 45 years is chosen.

Primary conductor

The primary conductor typical useful life is 60 years per the Kinectrics report. Sometimes the conductor will get replaced with the pole line at 45 years of life. During rebuilds, the conductor is transferred from old poles over to the new poles. Conductor is normally replaced because they are undersized, not due to failure. In a single pole swap the conductor will not be changed, but if there is a rebuild of all poles, the conductor would likely be changed. Conversion projects are being done in neighborhoods where the age of the system is 35 to 40 years. Conversion projects are selected typically due to undersized units as opposed to the conductor being at the end of its life. When substations are being phased out, the wire will be replaced. New wire is typically installed in the conversion projects. As the wire will last longer than the poles, the useful life is greater than 45 years. Wire has been replaced due to technology changes not as a result of system failure. One-quarter of the system has been updated and the remaining portion of the system is older. There is higher electrical stress on the older system. Capital plans will require changeover sooner than the physical requirements (due to age, voltage, conversions and physical condition). Currently the older system has shorter pole spans. As a result there is less mechanical stress but perhaps greater electrical stress due to higher loading. Kinectrics based the typical useful life on moderate mechanical stress, low electrical loading and moderate environmental conditions. The updated newer system has slightly higher mechanical stress since the pole span is greater but has a lower electrical load because the system has been upgraded. The older system has lower mechanical stress, but higher electrical loading. The environmental factors vary over the territory as well. Some areas have lower environmental factors (e.g. urban areas) while the rural areas have higher environmental factors. Therefore, the factors are similar to the Kinectrics typical life factors. Therefore a useful life of 60 years is chosen for the conductor.

Switches

There are a variety of switch types in the system. Line switches do not typically fail before a wire/pole fails and therefore have a life of 45 or more years.~~.~~ There is a switch maintenance program in place and load interrupter switches undergo annual maintenance. Fused cutouts may not last as long as a pole (i.e. <45 years). When the fuse gets triggered there is a higher chance of failure. An inline solid switch will last much longer than a fuse switch. Currently there are more fused cutouts than there are inline solid switches in the system. The average life of fused cutouts is about 25 years. The average of the two types is about 40 years. Therefore, the useful life for overhead switches is determined to be 40 years.

Transformers

The typical Kinectrics useful life for Overhead Transformers of 40 years is based on low mechanical stress, moderate electrical loading and moderate environmental factors. Many of the transformers are under loaded for electrical in the rural areas. So a portion of the system is under-loaded. Therefore, the useful life would be more than typical life but not at maximum useful life. Environmental factors are higher in rural areas than in urban areas. On average the factors affecting the useful life of the transformers have the typical impact as identified in the Kinectrics report for typical useful life. The factors vary over the Norfolk territory. The average typical life is estimated for overhead transformers. Therefore, the useful life of overhead transformers is 40 years.

Underground System

The underground system is comprised of a number of components. Primary and secondary cable, transformers, ducts, foundations, cable chambers switchgear and switches. Some of these components are already split in the accounting records. Norfolk has all types of primary cable except for lead-PILC. Most of the cable in the system is direct buried (EXLPE/TR). Most of the cable types have similar useful lives. Primary cable will be one component. Overhead and underground secondary cable is currently combined in the accounting records. The useful life is the same for both, so overhead and underground secondary cable will be one component. Pad-mount transformers, vault transformers, UG foundations, UG vaults, UG vault and pad-mount switchgear are currently grouped in the accounting records. Switchgear and transformers have comparable useful lives. Foundations and vaults have longer useful lives than the transformer but the majority of the dollars invested are with the transformers so impact would not be significant. One component will be used for transformers comprised of: pad-mount transformers, vault transformers, UG foundations, UG vaults and UG vault and pad-mount switchgear. Underground conduit comprised of ducts, duct banks and cable chambers have similar useful lives and will be treated as one component – underground conduit.

Cable

Norfolk Power has not had any problems with direct buried lines. The Kinectrics report indicates typical life is based on moderate mechanical stress, electrical loading and environmental factors. Mechanical stress and electrical loading are typical in the company's system. The life of the lines is greater than typical life because of limited failures. Kinectrics typical life for EXLPE/TR is 25 years with a maximum of 30 years. Kinectrics typical life for the other cable types range from 20 to 55 years. Overall there is less of a load in the Norfolk's system. As such, the expected useful life will be greater than typical. There is also less digging in the Norfolk's territory compared with a highly urban environment. This would also suggest the life is greater than typical. Maximum life of 30 years will be used.

The Kinectrics report has a typical life from 25 to 60 years for Secondary Cable. The Kinectrics report indicates typical life is based on moderate mechanical stress, electrical loading and environmental factors. Norfolk Power has no PILC cable but has both direct buried and in duct cabling, the majority of which is buried. In duct, cable has only been used since 2000 and therefore there is not much data on typical useful life. Secondary overhead and underground cables should last the same time. There have not been many faults on underground cable which suggests that the life is longer than typical. The maximum life for direct buried cable is 40 years as per the Kinectrics report. Therefore, a useful life of 40 years is chosen for both underground cable and overhead secondary cable.

Underground Transformers

Norfolk has no network transformers, only pad-mounted and a few submersible transformers. This component is comprised of transformers, foundations, vaults, switches and switchgear. Foundations and vaults have a longer useful life than than transformers and switchgear but do not represent a large portion of the overall cost. The Kinectrics typical life is between 20 and 45 years for transformers and between 20 and 45 years for switches and switchgear. The Kinectrics report identifies electrical loading as moderate for transformers and low for switchgear. Environmental factors are moderate for transformers and high for switchgears. Since the underground system is not typically overloaded, there have been limited switching issues, or cable faults, so the typical useful life is appropriate. Therefore, the average useful life for the transformer component is 35 years. The transformer component includes transformers, vaults, foundations, switches and switchgear.

Underground Conduit

The majority of the cost is in the ducts with less insignificant costs for concrete and chambers. The Kinectrics report indicates typical useful life is 50 years. The Kinectrics report also identifies mechanical stress as high and environmental factors as moderate. As there is nothing in Norfolk's system that would suggest a difference in these factors a useful life of 50 years is chosen.

SCADA Equipment

Most of the stations are outdoors so environmental elements are a factor, but at a lower influence. Technological change is what drives the useful life of this equipment. Kinectrics report identifies the typical life as 20 years. The Kinectrics report also indicates that non-physical factors are high and environmental factors as low. As the company does not have 20 years of experience with SCADA and there is nothing to indicate that the useful life is different from the typical useful life, a useful life of 20 years is chosen.

Transformer Stations

Transformer stations are comprised of the power transformer, station service transformer, the station grounding transformer, the station DC system and the switchgear. The station grounding transformer has a useful life that is not significantly different than the power transformer. Therefore these transformers will be grouped together as one component under Transformers. Both the DC system and the switchgear make up significant costs of a transformer. Each will be considered as separate components.

Power Transformers

Norfolk currently has one transformer station. The Kinectrics report has a typical useful life for the power transformers of 45 years and is based on electrical loading and environmental factors as being moderate. The transformer is several years old but is expected that it will last the typical life given a regular maintenance schedule. Currently the electrical loading is low. Norfolk Power has selected a useful life of 45 years.

Stations DC Systems

The Kinectrics report shows a typical useful life of 20 years. The Kinectrics report identifies the utilization factors as moderate for electrical loading, low for environmental conditions and operating practices and moderate for maintenance practices and non-physical factors. Nothing was noted that would make the useful life different from the typical life. Therefore, useful life of 20 years is chosen.

Station Metal Clad switchgear
The Kinectrics report shows a typical useful life of 40 years. The report also identifies utilization factors as low for mechanical stress and electrical loading, and moderate for environmental factors, operating practices, maintenance practices and non-physical factors. As there is not a lot of operating impact (opening and closing of the breakers) the operating practices impact is moderate. Therefore, the typical useful life of 40 years is chosen.

Distribution Station Equipment
The majority of the equipment stays outside while some components of the stations are housed indoors. There are currently 12 distribution stations. NP5 is partly housed indoors. The stations will be phased out as the conversion project progresses, however, it is not known how quickly this will occur. The remaining life of these stations, if not removed from service due to the conversion project, would be about 20 years, based upon experience with older existing stations.

Minor assets

Smart meters consist of the meter and the software each having different useful lives. Smart meters have a 10 year seal requiring recertification at the end of the 10 year period. These meters are influenced by technological obsolescence. A useful life of 10 years is chosen. Smart meter software life is limited by technological changes so the life is 5 years. Residential meters tend to have a longer useful life but most of these meters are now stranded meters and the remainder will be replaced with smart meters. Wholesale, commercial and industrial meters are interval meters which are similar to smart meters in that they are electronic meters. Useful lives of these types of meters are similar so they will be grouped as one component. Experience has shown that the useful life of these meters is 25 years. CTs and PTs are a significant component of the meter inventory. CTs & PTs will be a separate component. The useful life of the CTs & PTs component is 30 years.

Office equipment is currently being depreciated over 10 years. Kinectrics identifies a useful life range of 5 to 15 years so a useful life of 10 years is chosen.

There are two different types of trucks – bucket and pickup. There is currently a 7 year replacement program for pickup trucks and a 15 year replacement program for bucket trucks. Therefore, bucket trucks useful life is 15 years and other vehicles useful life is 7 years.

Administrative buildings have a useful life of 50 years.

Station building has a Kinectrics range of useful lives of 50 to 75 years. The life of the building is similar to the administration building. As such, the useful life is 50 years.

Computer equipment is comprised of servers, laptops and printers. Servers are currently lasting 5 to 6 years. Laptops and printers are lasting 3 years. Therefore, the average is 4 years for computer equipment as a group. Useful life is therefore determined to be 4 years.

Most computer software is acquired on a 4 year licensing cycle. Therefore, useful life is determined to be 4 years.

Equipment kinectrics life range is 5 to 10 years. As the tools are used daily and newer technology forces replacement, a useful life of 5 years is chosen.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2011. The net book value, as deemed cost exemption (available to rate regulated entities), will be applied so that the opening values at January 1, 2011 do not need to be restated. As such, componentization does not need to be applied retroactively.

Table 1: NPDI – PP&E Components and Estimated Useful Lives

Component	Proposed Useful Life
Land	N/A
Overhead System	
- Poles	45
- Primary Conductor	60
- Overhead Switches	40
- Overhead Transformers	40
Underground System	
- Cable	30
- Secondary Underground Cable	40
- Secondary Overhead	40
- Underground Transformers	35
- Underground Conduit	50
SCADA Equipment	20
Transformer Stations	
- Power Transformers	45
- Stations DC Systems	20
- Station Metal Clad Switchgear	40
Distribution Station Equipment	20
Minor Assets	
Meters - Smart meters - Smart meter software - Interval meters - CTs & PTs	 10 5 25 30
Office Equipment	10
Vehicles -Pickup Trucks - Bucket Trucks	7 15
Administrative Buildings	50
Station Buildings	50
Computer Equipment	4
Computer Software	4
Equipment	5

APPENDIX 7 – BOARD STAFF INTERROGATORIES

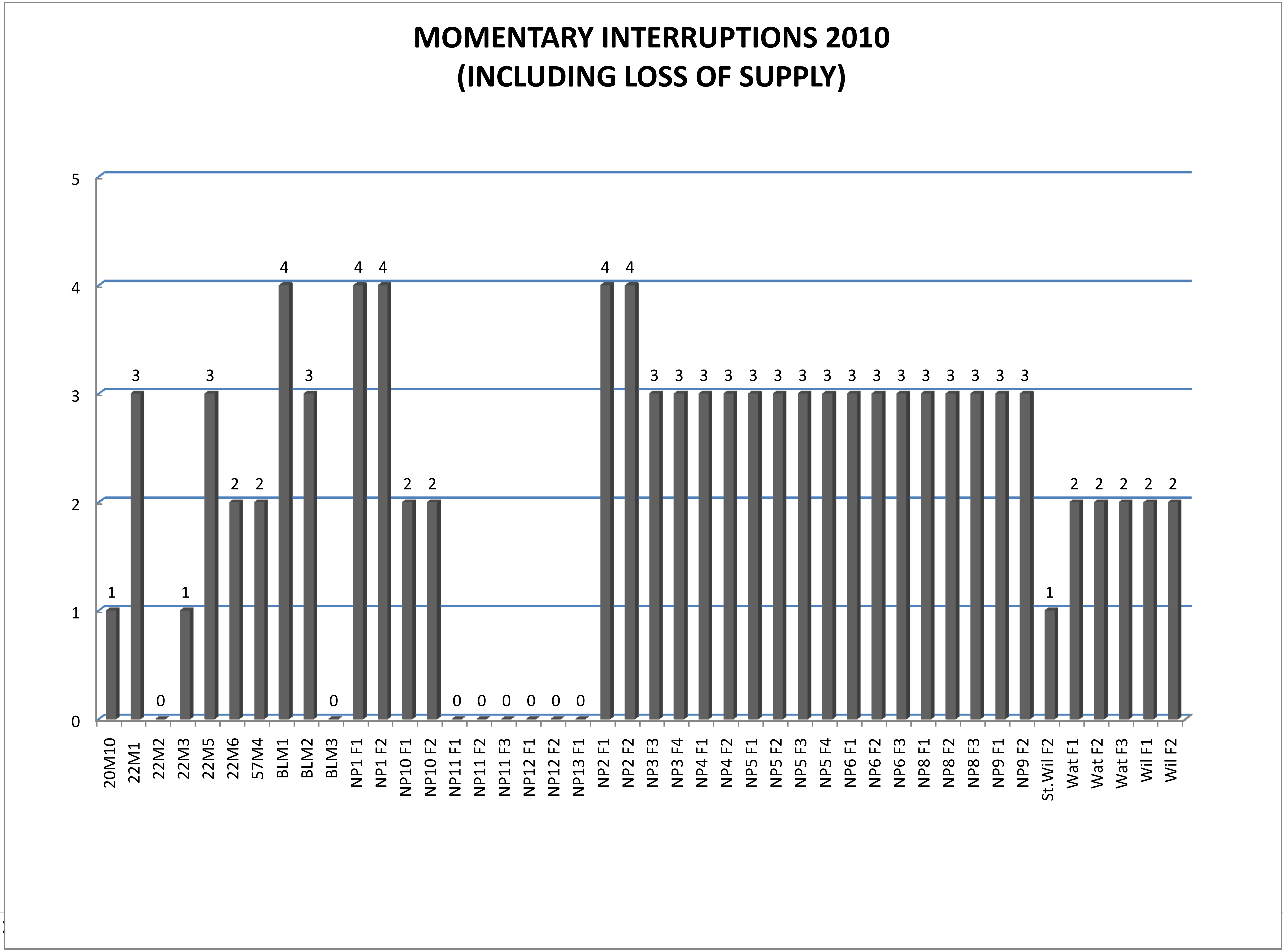
Worst Performing Feeders for 2010 and 2011 BS IR#32)

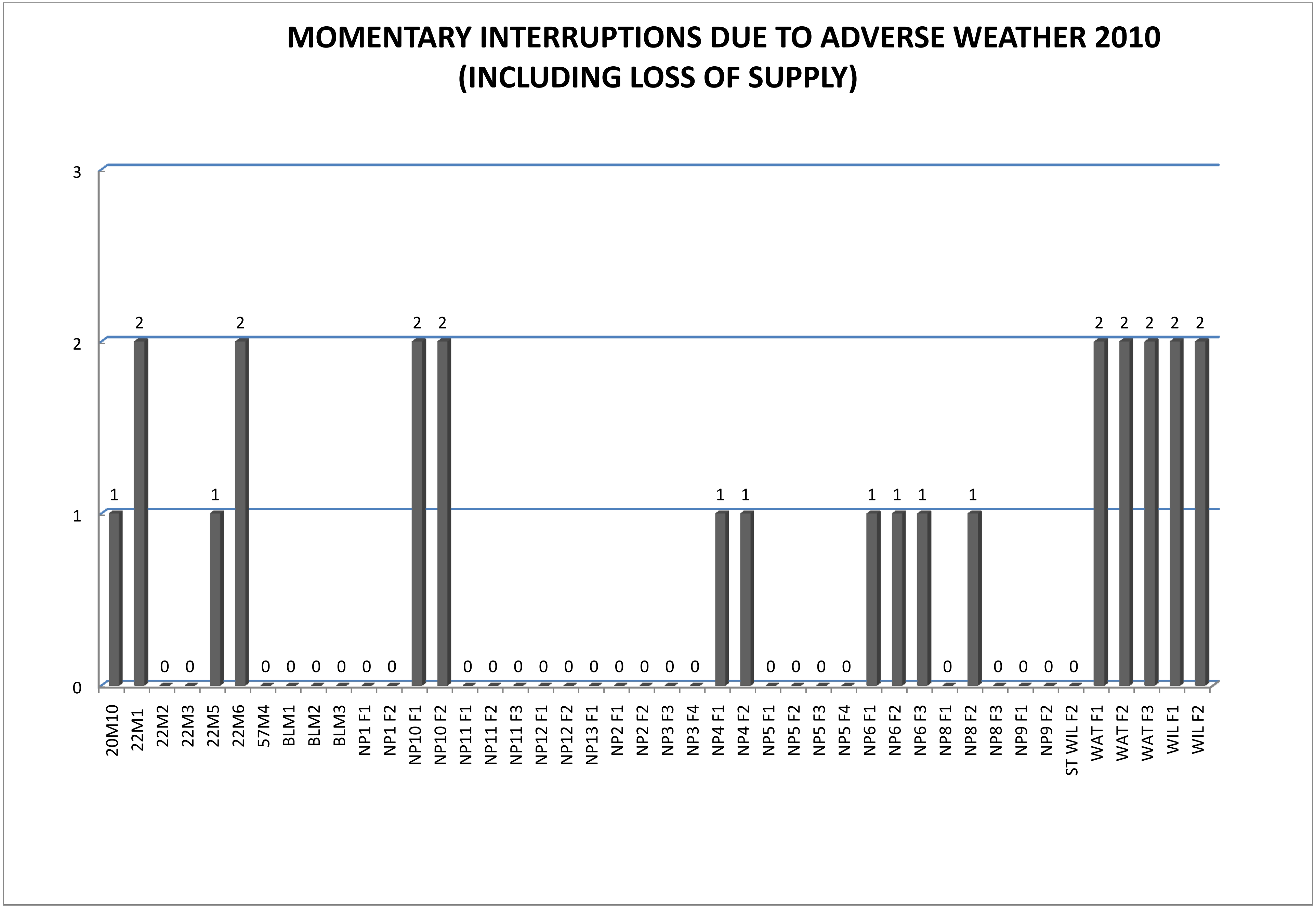
NORFOLK POWER 2010

FEEDER PERFORMANCE & RANKING

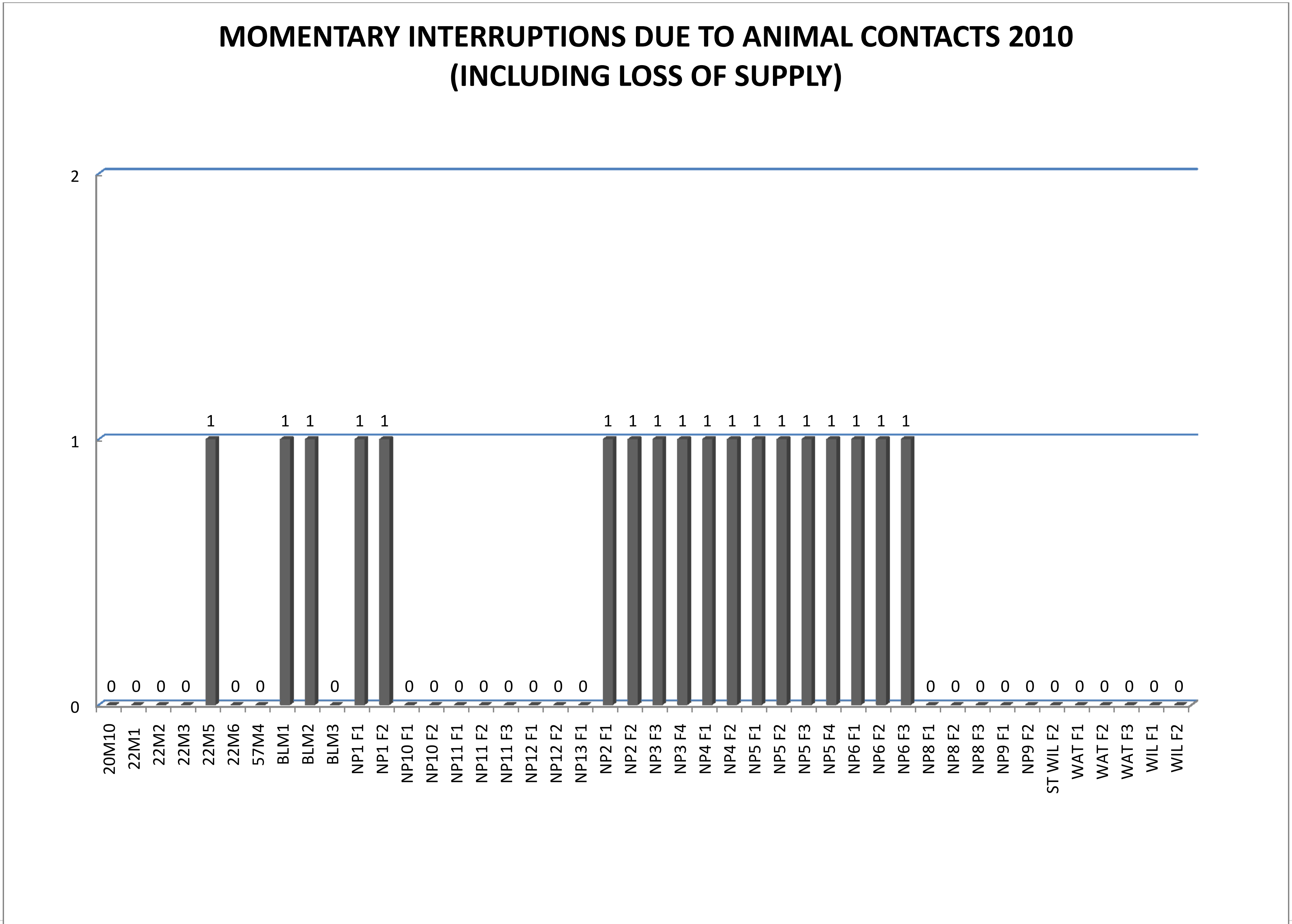
NORFOLK POWER FEEDER PERFORMANCE RANKING

1ST WORST PERFORMING FEEDER	22M6	30 EVENTS
2ND WORST PERFORMING FEEDER	57M4-BLM3	23 EVENTS
3RD WORST PERFORMING FEEDER	WAT F1	11 EVENTS
4TH WORST PERFORMING FEEDER	BLM2	9 EVENTS
5TH WORST PERFORMING FEEDER	22M5	7 EVENTS
6TH WORST PERFORMING FEEDER	WIL F2	6 EVENTS
7TH WORST PERFORMING FEEDER	NP4 F1	6 EVENTS
8TH WORST PERFORMING FEEDER	NP8F2	4 EVENTS
9TH WORST PERFORMING FEEDER	WAT F3	4 EVENTS
10TH WORST PERFORMING FEEDER	22M2	4 EVENTS


MOMENTARY INTERRUPTIONS 2010
(INCLUDING LOSS OF SUPPLY)
0
1
2
3
4
5
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
St.Wil F2
Wat F1
Wat F2
Wat F3
Wil F1
Wil F2
1 3 0 1 3 2 2 4 3 0 4 4 2 2 0 0 0 0 0 0 4 4 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 1 2 2 2 2 2



MOMENTARY INTERRUPTIONS DUE TO ADVERSE WEATHER 2010
(INCLUDING LOSS OF SUPPLY)
3
2
1
0
20M10 1
22M1 2
22M2 0
22M3 0
22M5 1
22M6 2
57M4 0
BLM1 0
BLM2 0
BLM3 0
NP1 F1 0
NP1 F2 0
NP10 F1 2
NP10 F2 2
NP11 F1 0
NP11 F2 0
NP11 F3 0
NP12 F1 0
NP12 F2 0
NP13 F1 0
NP2 F1 0
NP2 F2 0
NP3 F3 0
NP3 F4 0
NP4 F1 1
NP4 F2 1
NP5 F1 0
NP5 F2 0
NP5 F3 0
NP5 F4 0
NP6 F1 1
NP6 F2 1
NP6 F3 1
NP8 F1 0
NP8 F2 1
NP8 F3 0
NP9 F1 0
NP9 F2 0
ST WIL F2 0
WAT F1 2
WAT F2 2
WAT F3 2
WIL F1 2
WIL F2 2


MOMENTARY INTERRUPTIONS DUE TO ANIMAL CONTACTS 2010
(INCLUDING LOSS OF SUPPLY)
2
1
0
20M10 22M1 22M2 22M3 22M5 22M6 57M4 BLM1 BLM2 BLM3 NP1 F1 NP1 F2 NP10 F1 NP10 F2 NP11 F1 NP11 F2 NP11 F3 NP12 F1 NP12 F2 NP13 F1 NP2 F1 NP2 F2 NP3 F3 NP3 F4 NP4 F1 NP4 F2 NP5 F1 NP5 F2 NP5 F3 NP5 F4 NP6 F1 NP6 F2 NP6 F3 NP8 F1 NP8 F2 NP8 F3 NP9 F1 NP9 F2 ST WIL F2 WAT F1 WAT F2 WAT F3 WIL F1 WIL F2
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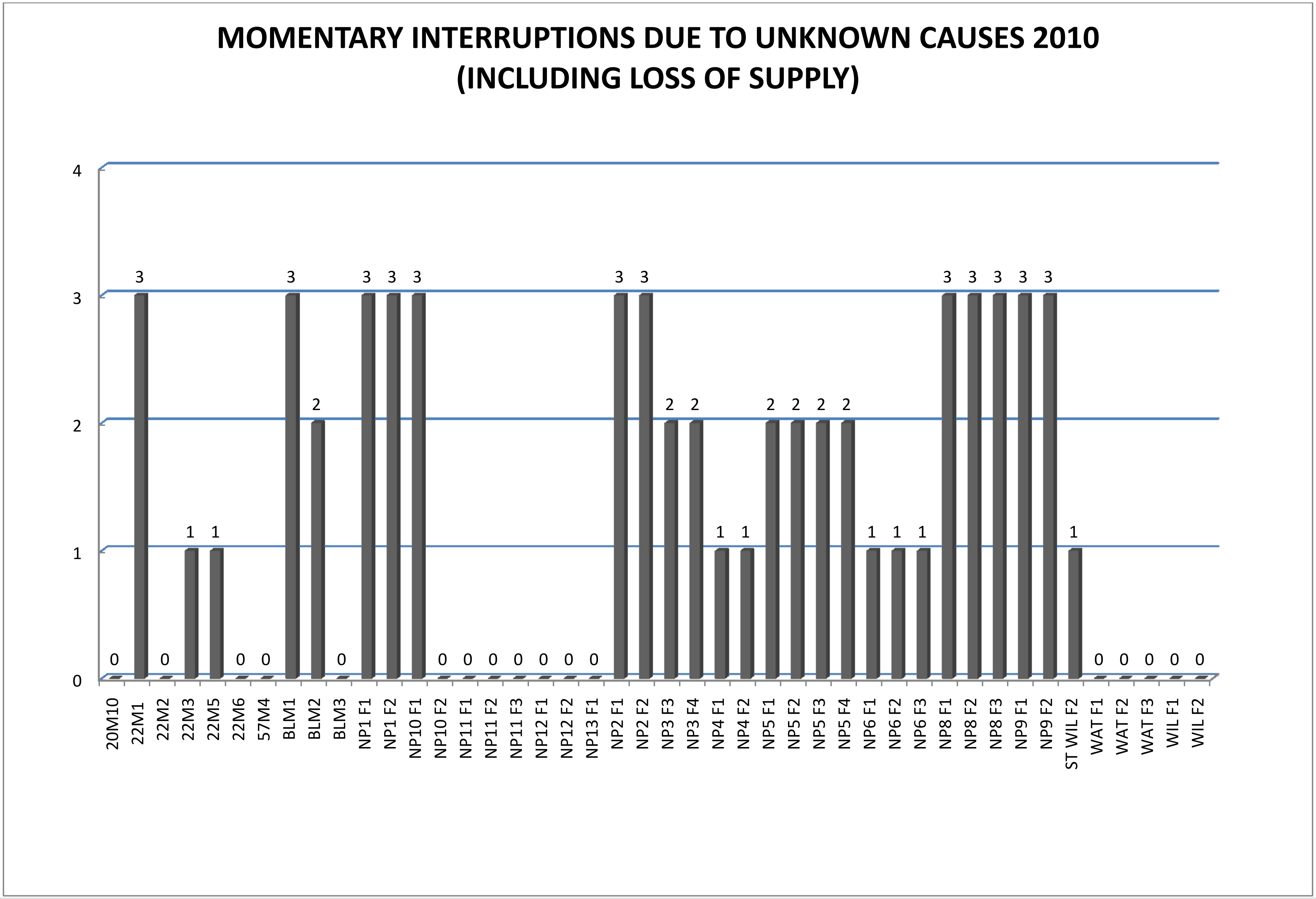
MOMENTARY INTERRUPTIONS DUE TO UNKNOWN CAUSES 2010
(INCLUDING LOSS OF SUPPLY)
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1
2
3
4
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
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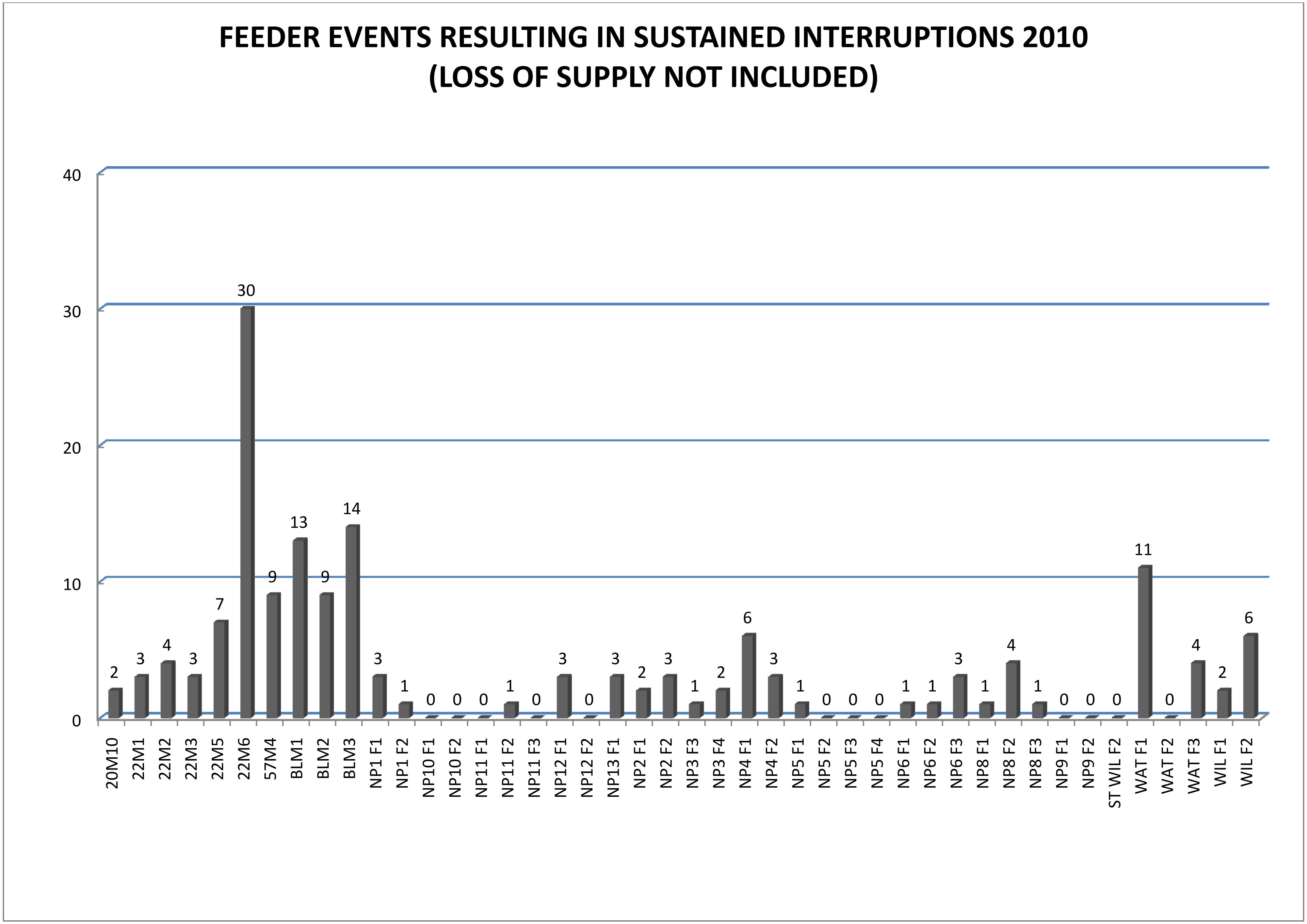
WIL F2


FEEDER EVENTS RESULTING IN SUSTAINED INTERRUPTIONS 2010
(LOSS OF SUPPLY NOT INCLUDED)
0
10
20
30
40
20M10 2
22M1 3
22M2 4
22M3 3
22M5 7
22M6 30
57M4 9
BLM1 13
BLM2 9
BLM3 14
NP1 F1 3
NP1 F2 1
NP10 F1 0
NP10 F2 0
NP11 F1 0
NP11 F2 1
NP11 F3 0
NP12 F1 3
NP12 F2 0
NP13 F1 3
NP2 F1 2
NP2 F2 3
NP3 F3 1
NP3 F4 2
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NP5 F2 0
NP5 F3 0
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NP6 F2 1
NP6 F3 3
NP8 F1 1
NP8 F2 4
NP8 F3 1
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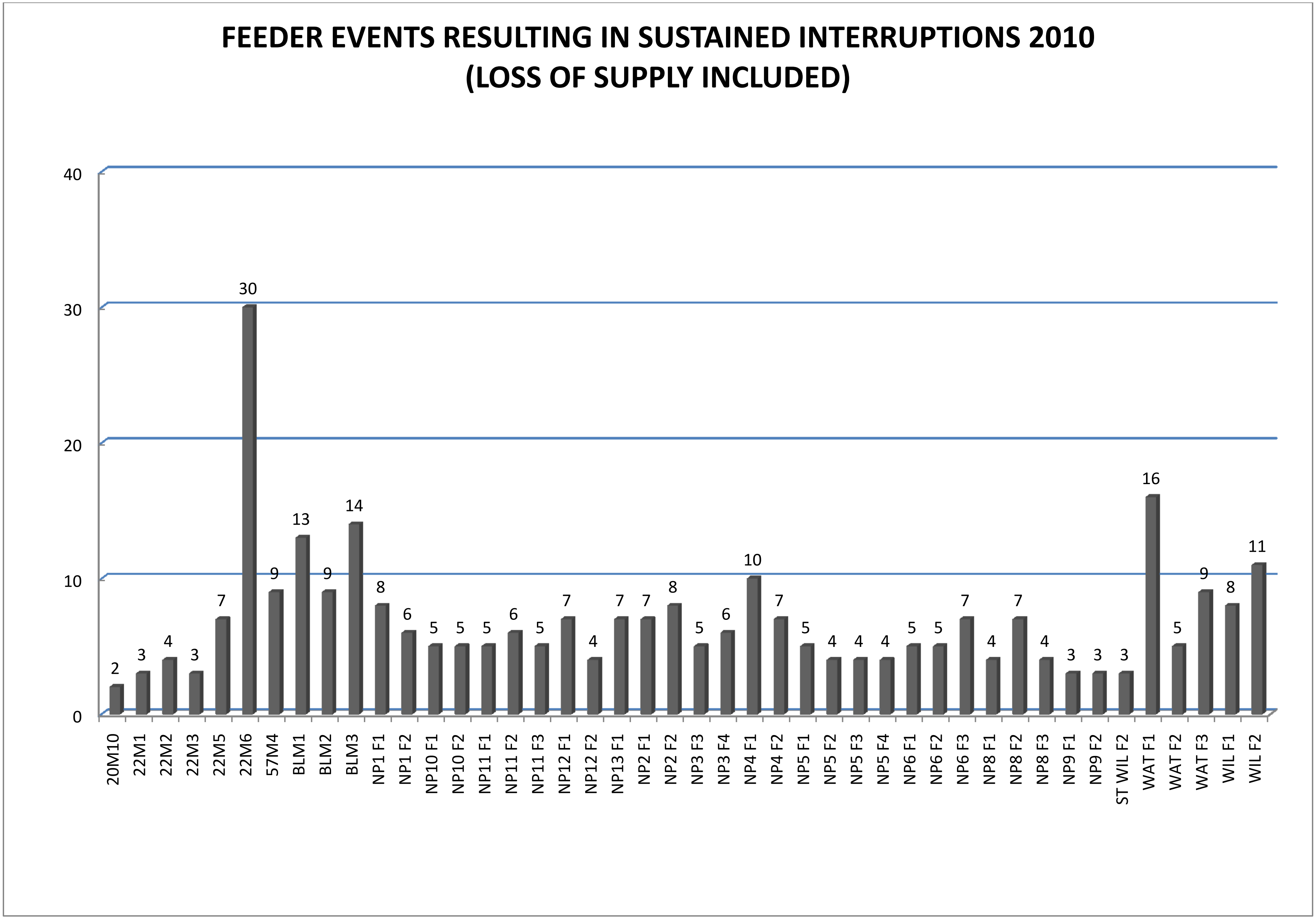
WAT F1 11
WAT F2 0
WAT F3 4
WIL F1 2
WIL F2 6


FEEDER EVENTS RESULTING IN SUSTAINED INTERRUPTIONS 2010
(LOSS OF SUPPLY INCLUDED)
0
10
20
30
40
2 3 4 3 7 30 9 13 9 14 8 6 5 5 5 6 5 7 4 7 7 8 5 6 10 7 5 4 4 4 5 5 7 4 7 4 3 3 3 16 5 9 8 11
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
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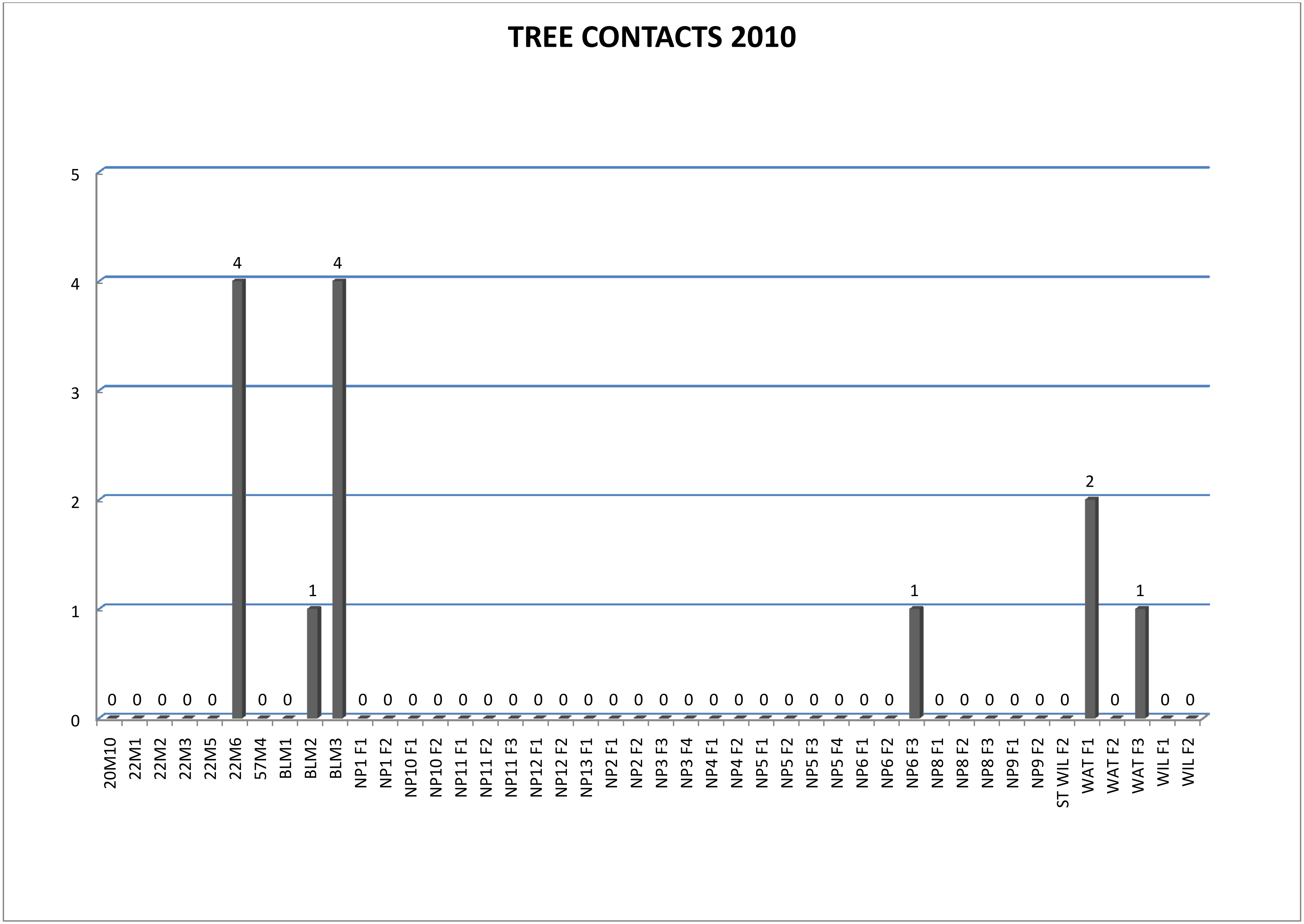
WIL F2



TREE CONTACTS 2010
5
4
3
2
1
0
4
4
1
1
2
1
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
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NP4 F2
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NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
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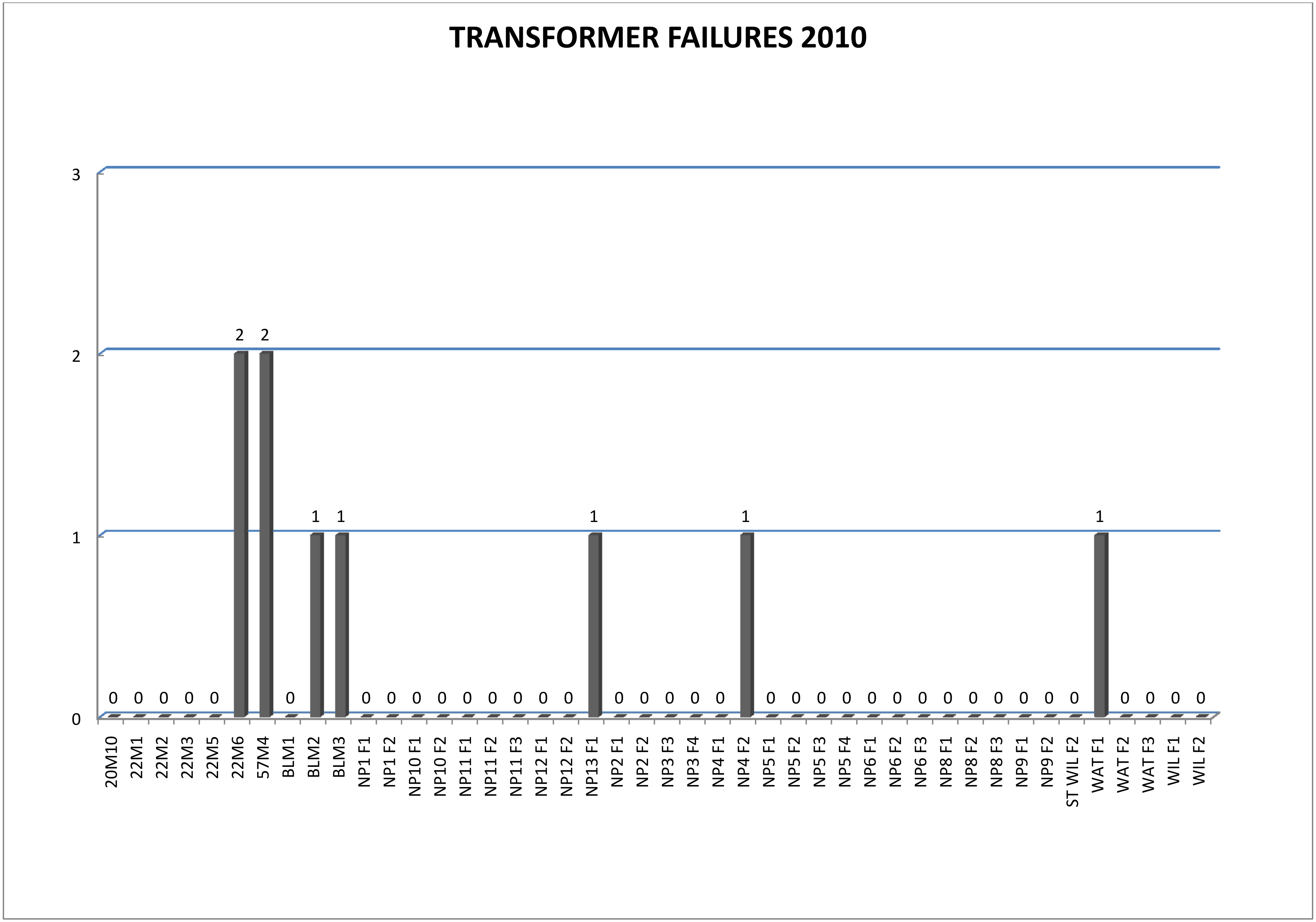
WIL F1
WIL F2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1
0
2 2 1 1 1 1 1
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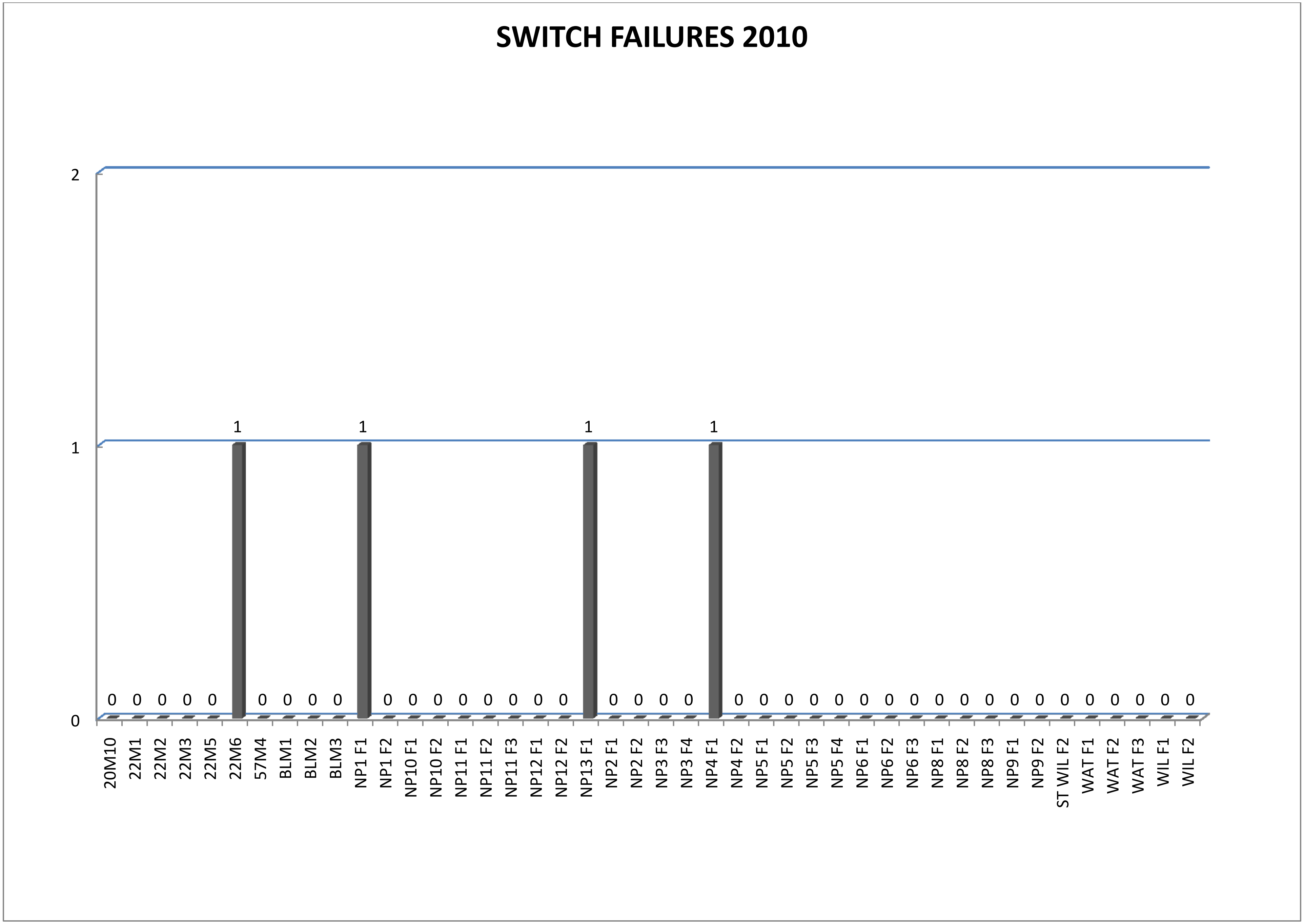
SWITCH FAILURES 2010
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1
1
1
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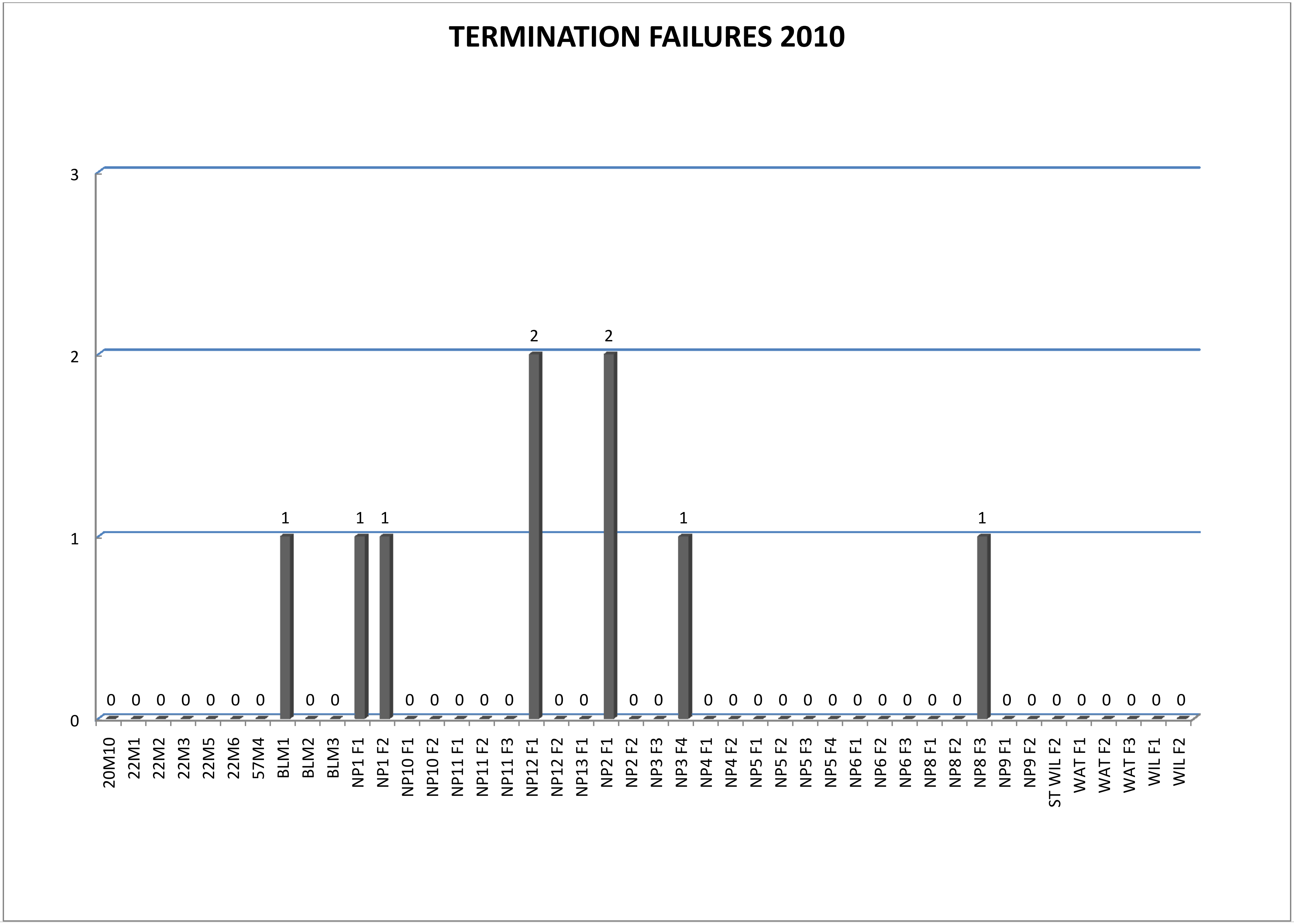
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


TERMINATION FAILURES 2010
3
2
1
0
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20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
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NP9 F2
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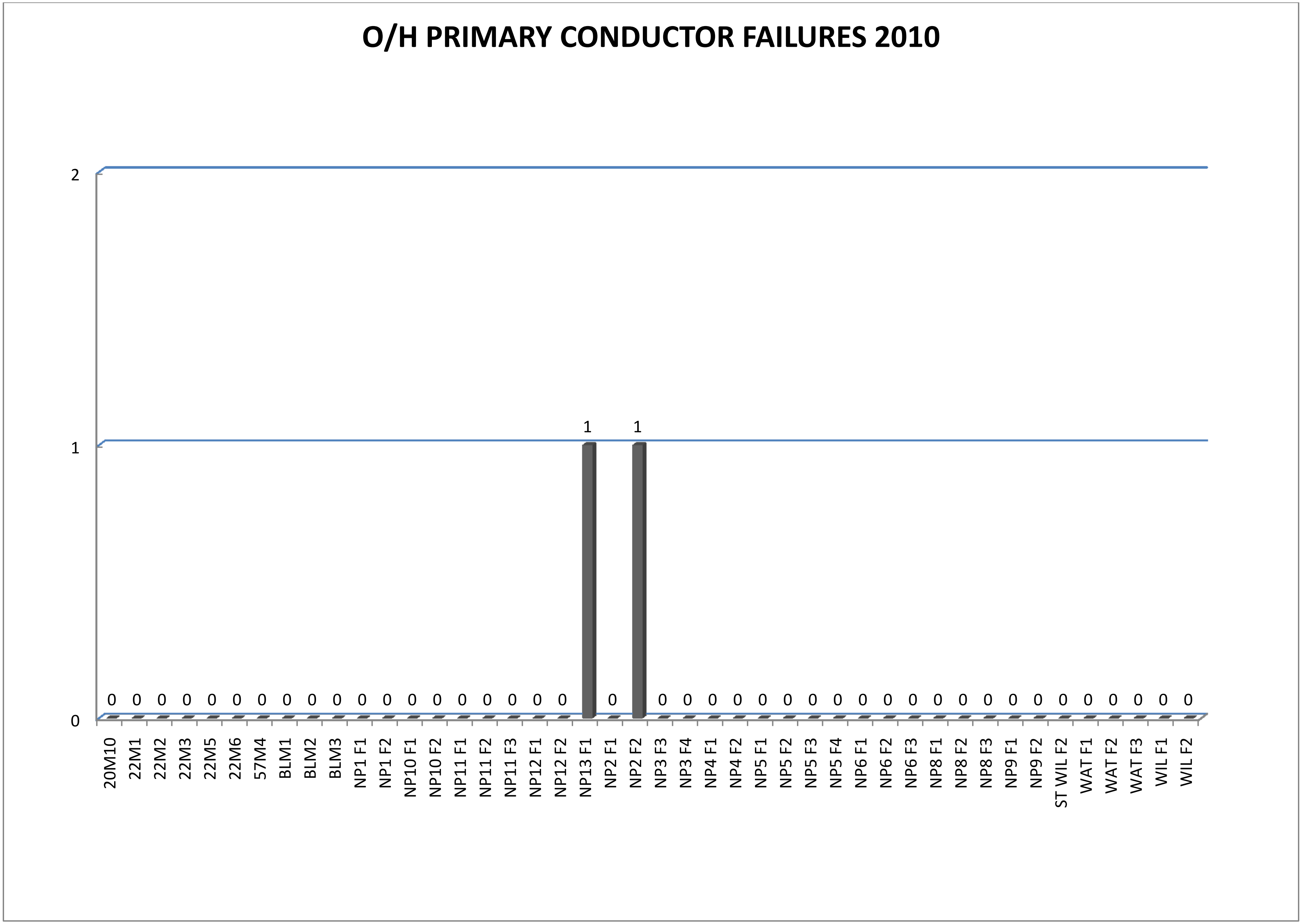
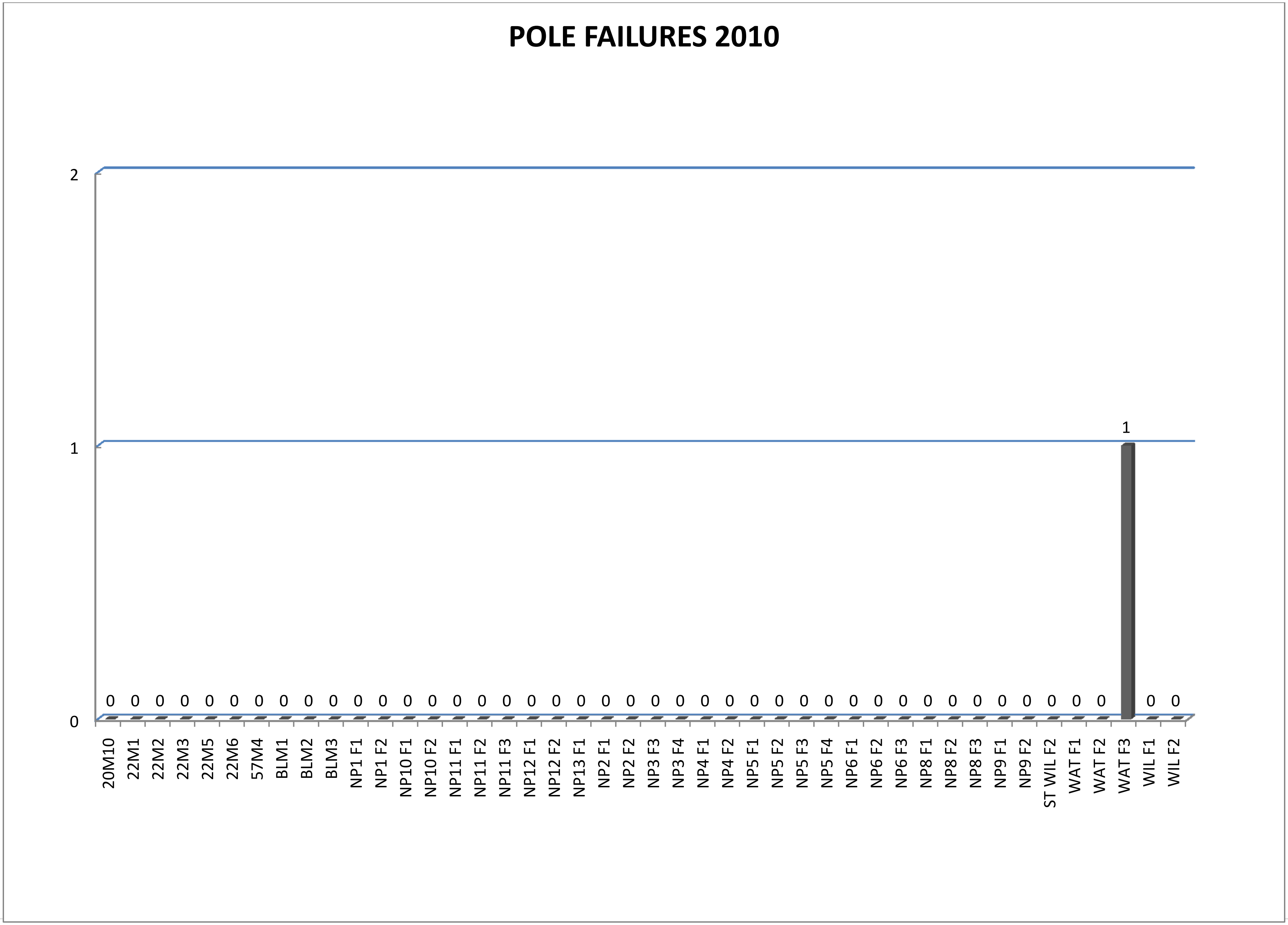
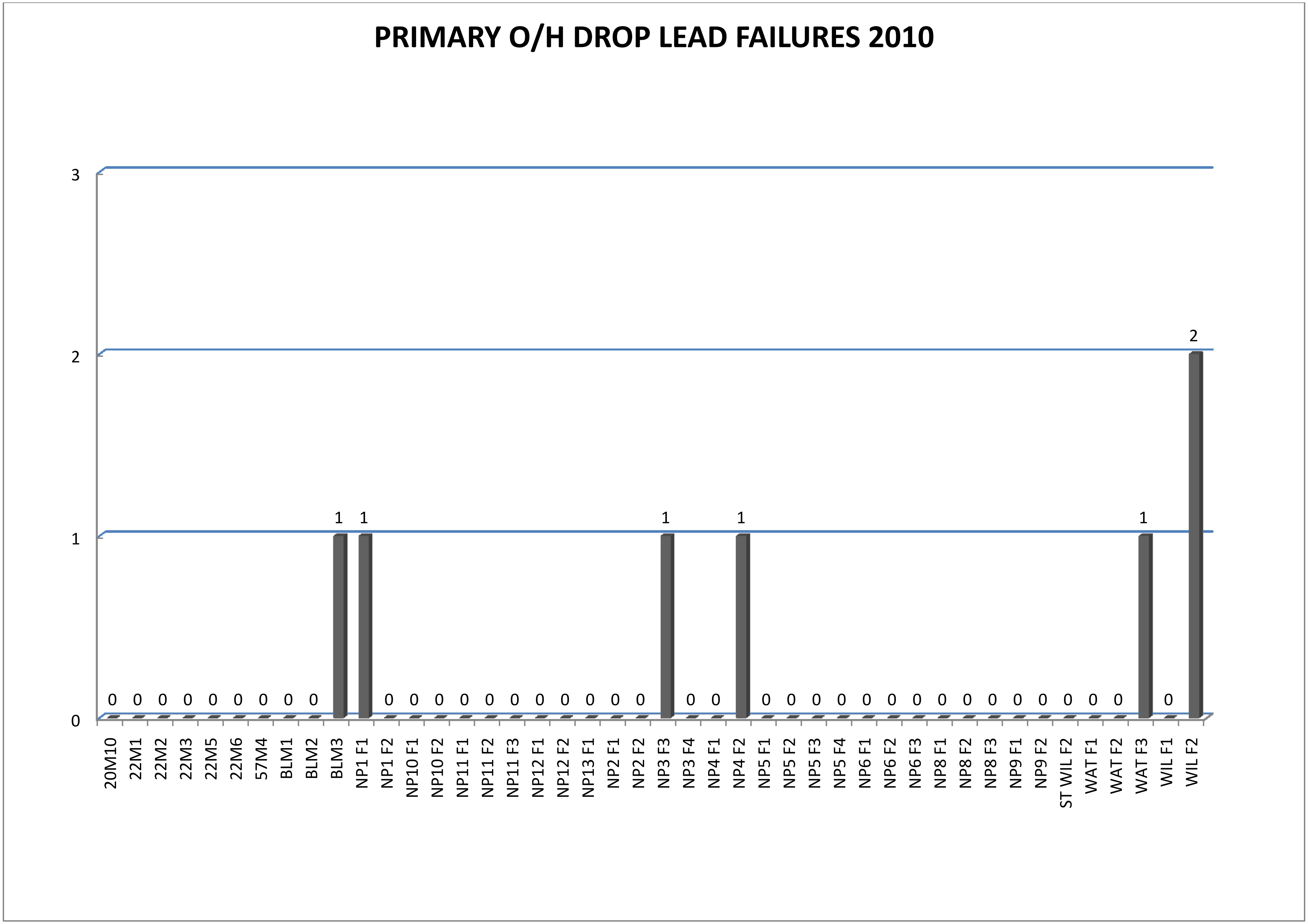
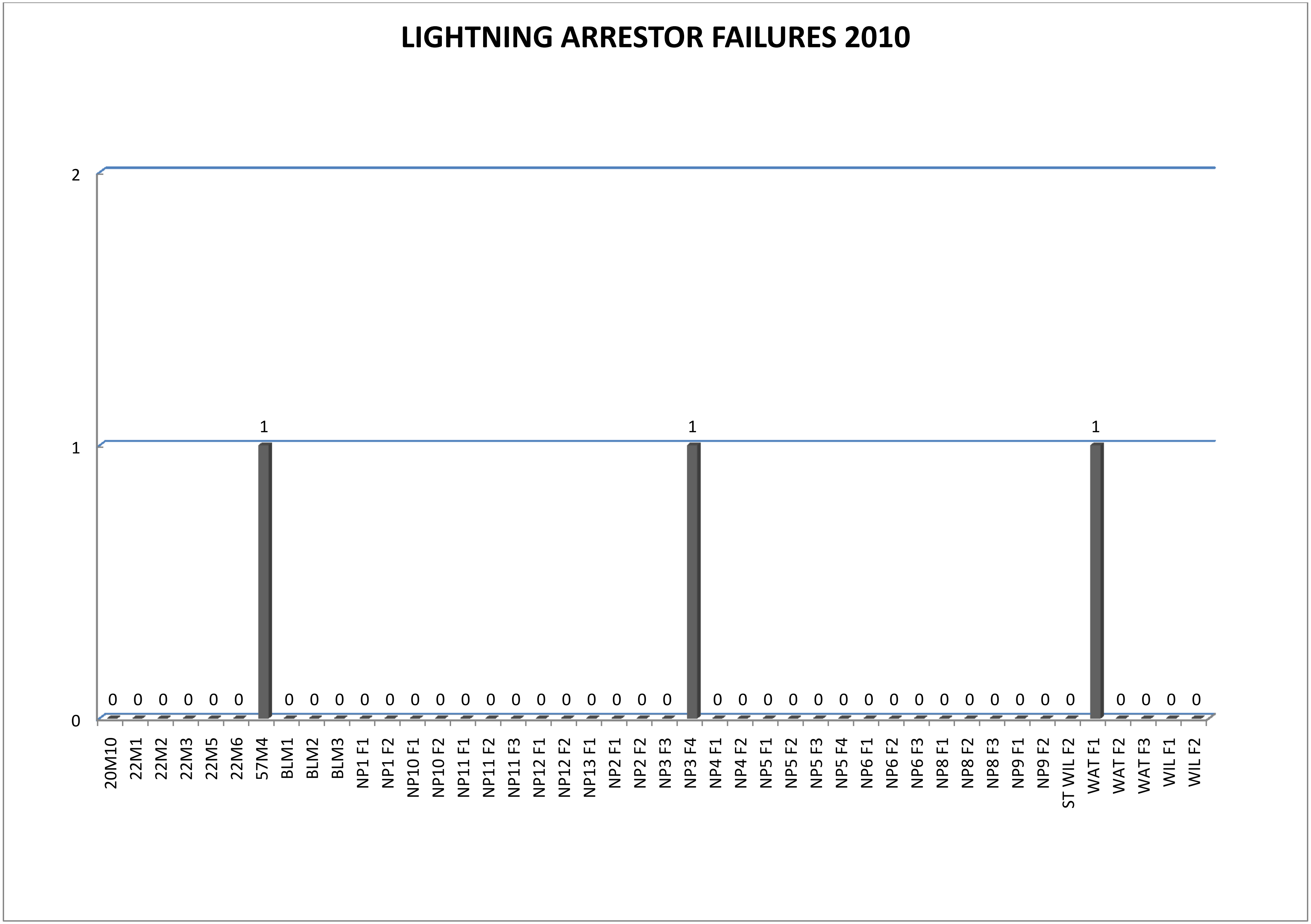
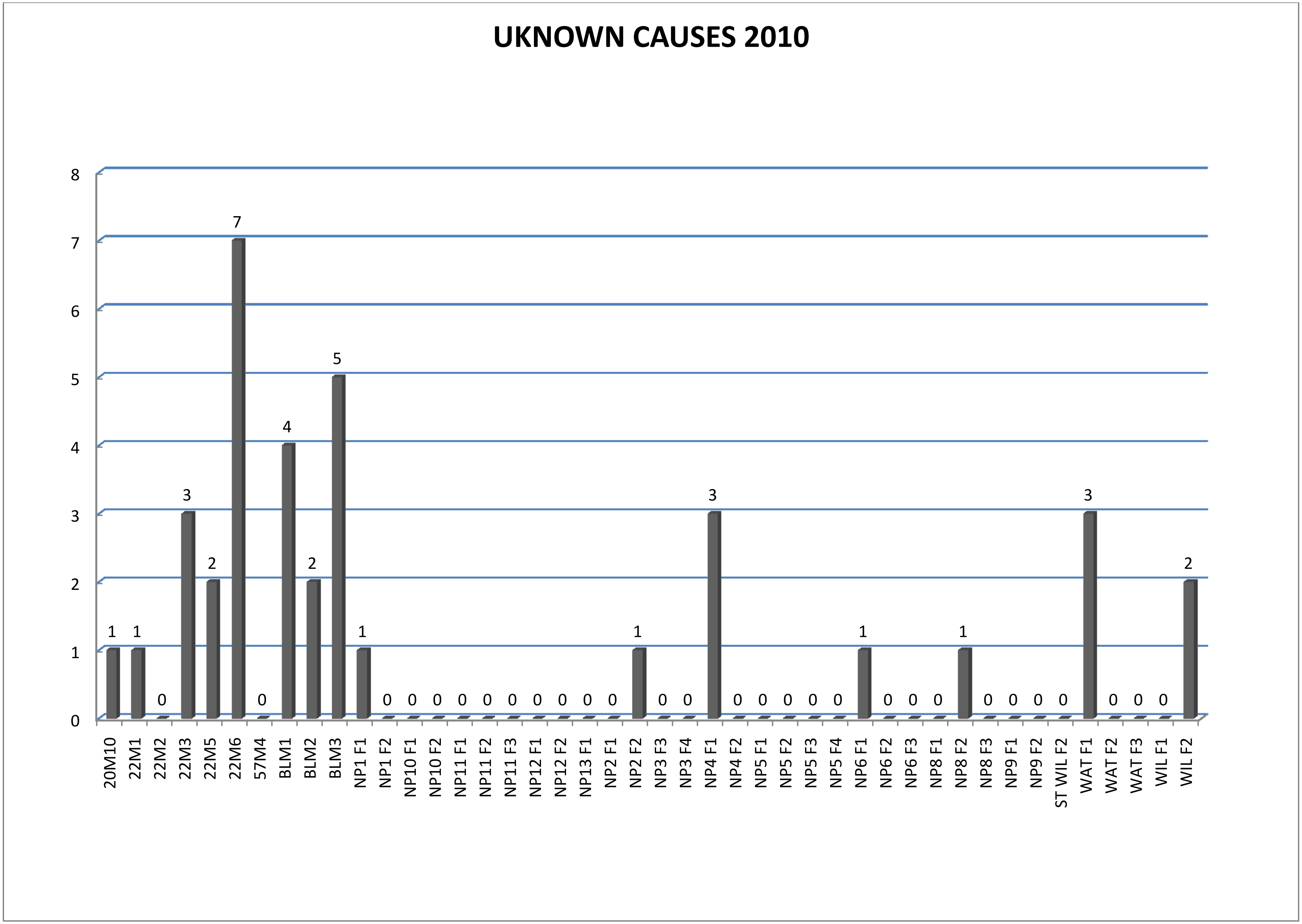
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


O/H PRIMARY CONDUCTOR FAILURES 2010
2
1
0
1
1
0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


POLE FAILURES 2010
2
1
0
1
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


PRIMARY O/H DROP LEAD FAILURES 2010
3
2
1
0
0 0 0 0 0 0 0 0 0 1 1 0 0 0 0 0 0 0 0 0 0 0 1 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 2
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


LIGHTNING ARRESTOR FAILURES 2010
2
1
0
1
1
1
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2



UKNOWN CAUSES 2010
8
7
6
5
4
3
2
1
0
1
1
0
3
2
7
0
4
2
5
1
0
0
0
0
0
0
0
0
0
0
1
0
0
3
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1
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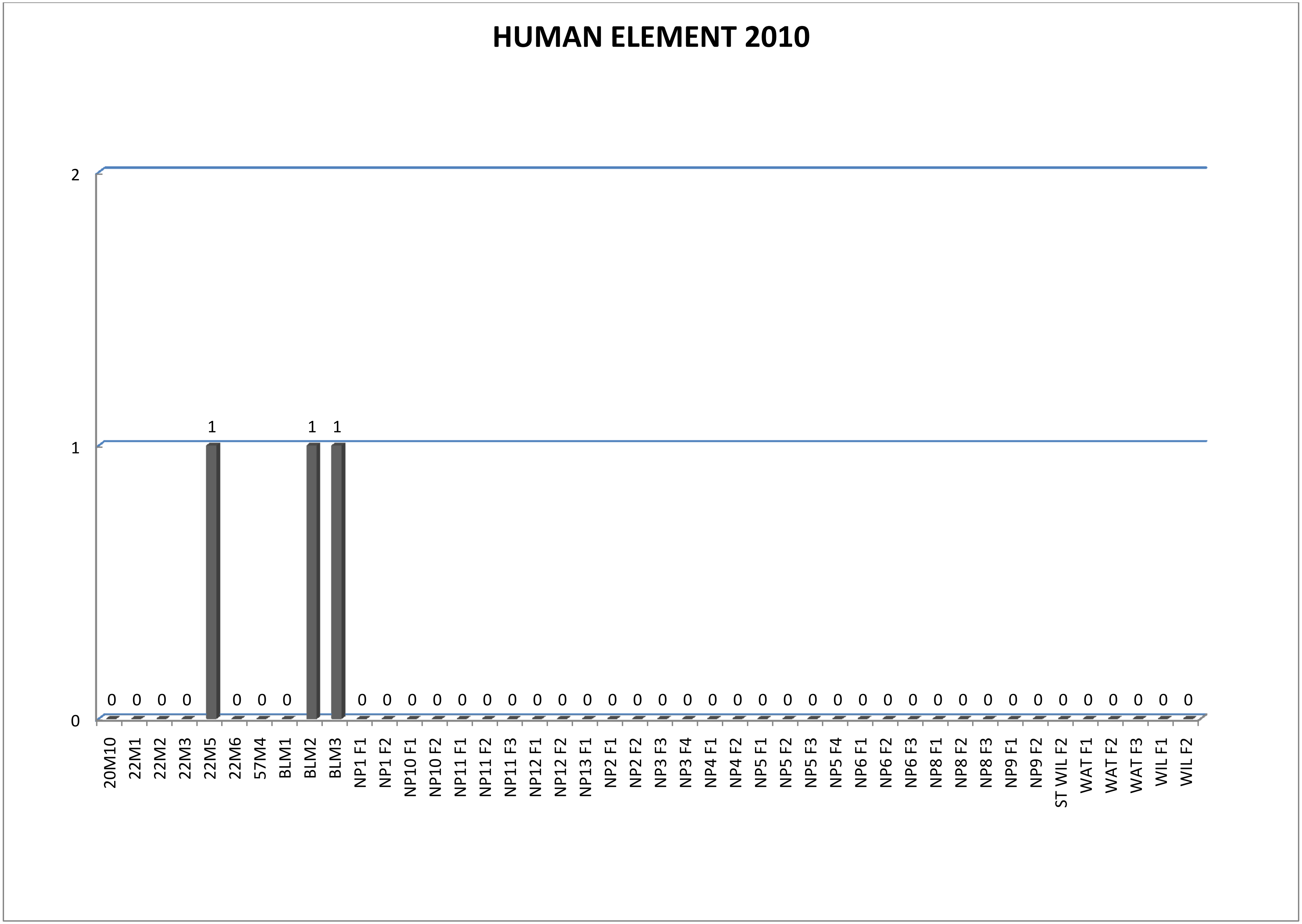
0
3
0
0
0
2
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


HUMAN ELEMENT 2010
2
1
0
1
1 1
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2

FEEDER EVENT SUMMARY

FEEDER	ADVERSE ENVIRONMENT-FIRE	ADVERSE WEATHER	HIGH WINDS	LIGHTNING	ANIMAL	BIRD	RACCOON	SQUIRREL	DIG IN	VEHICLE	DEBRIS IN PRIMARY	HUMAN ELEMENT	LOSS OF SUPPLY	TREE CONTACT	UNKNOWN	ARRESTOR FAILURE	DROP LEAD FAILURE	POLE FAILURE	PRIMO/H CONDUCTOR FAILURE	SEC O/H CONDUCTOR FAILURE	SWITCH FAILURE	TERMINATION FAILURE	TRANSFORMER FAILURE	SCORE
20M10		1													1									2
22M1		1		1											1									3
22M2				1		3																		4
22M3															3									3
22M5		1			1	1	1					1			2									7
22M6			1	3	4		3	5						4	7						1		2	**30**
57M4				5					1							1							2	9
BLM1	1					2	1	3							5							1		13
BLM2				1	1		1			1		1		1	2								1	9
BLM3					1		1					1		4	5		1						1	14
NP1 F1													5		1		1				1			3
NP1F2													5							1				1
NP2 F1											1		5									1		2
NP2 F2							1						5		1				1					3
NP3 F3													4				1							1
NP3 F4													4			1						1		2
NP4 F1				1			1						4		3						1			6
NP4 F2				1									4				1						1	3
NP5 F1									1				4											1
NP5F2													4											0
NP5 F3													4											0
NP5F4													4											0

FEEDER	ADVERSE ENVIRONMENT-FIRE	ADVERSE WEATHER	HIGH WINDS	LIGHTNING	ANIMAL	BIRD	RACCOON	SQUIRREL	DIG IN	VEHICLE	DEBRIS IN PRIMARY	HUMAN ELEMENT	LOSS OF SUPPLY	TREE CONTACT	UNKNOWN	ARRESTOR FAILURE	DROP LEAD FAILURE	POLE FAILURE	PRIMO/H CONDUCTOR FAILURE	SEC O/H CONDUCTOR FAILURE	SWITCH FAILURE	TERMINATION FAILURE	TRANSFORMER FAILURE	SCORE
NP6 F1													4		1									1
NP6 F2						1							4											1
NP6 F3				2									4	1										3
NP8 F1				1									3											1
NP8F2		2						1					3		1									4
NP8 F3													3									1		1
NP9 F1													3											0
NP9 F2													3											0
NP10 F1													5											0
NP10 F2													5											0
NP11 F1													5											0
NP11 F2		1											5											1
NP11 F3													5											0
NP12 F1		1											4									2		3
NP12 F2													4											0
NP13 F1													4						1			1	1	3

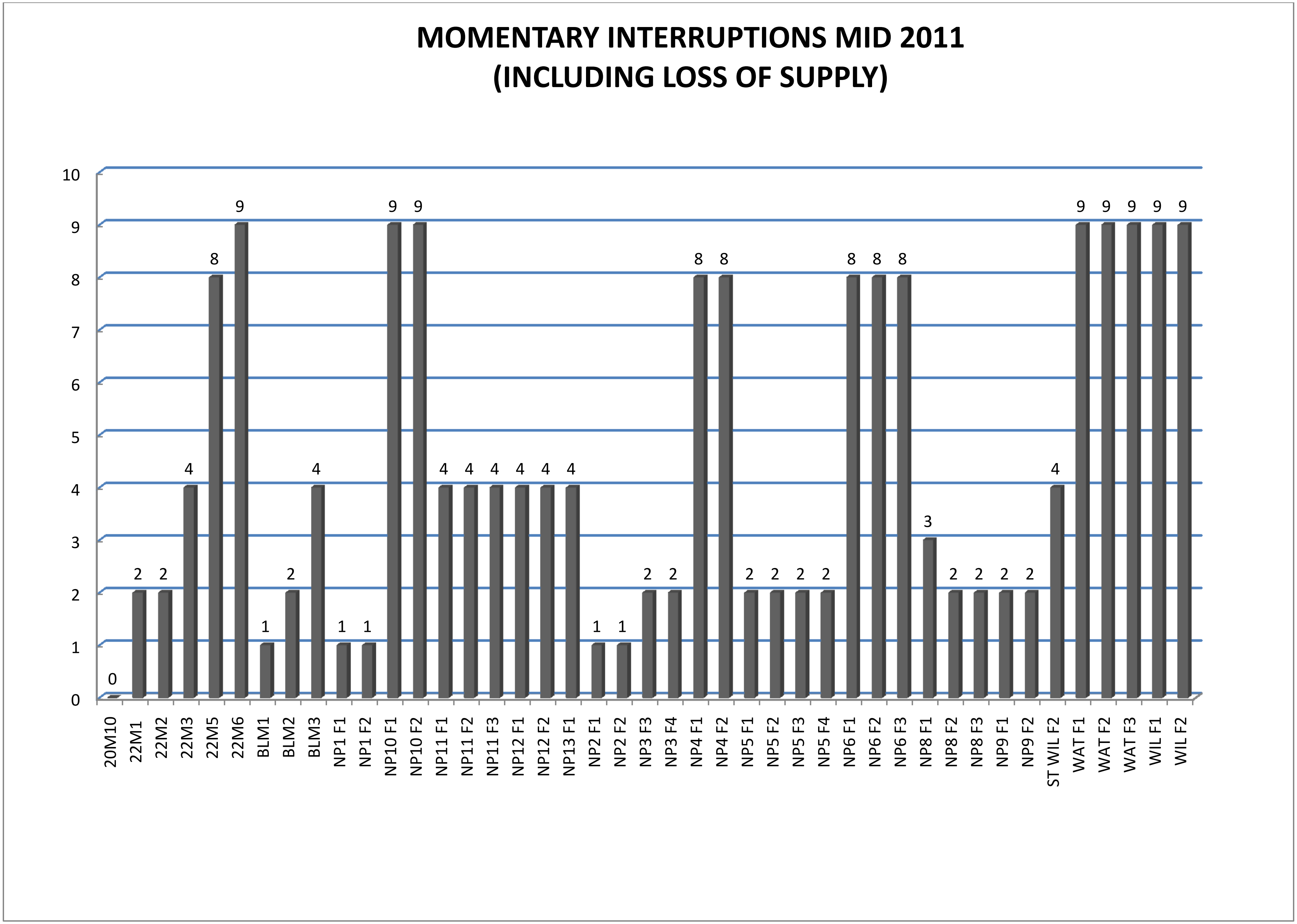
NORFOLK POWER 2011

FEEDER PERFORMANCE & RANKING

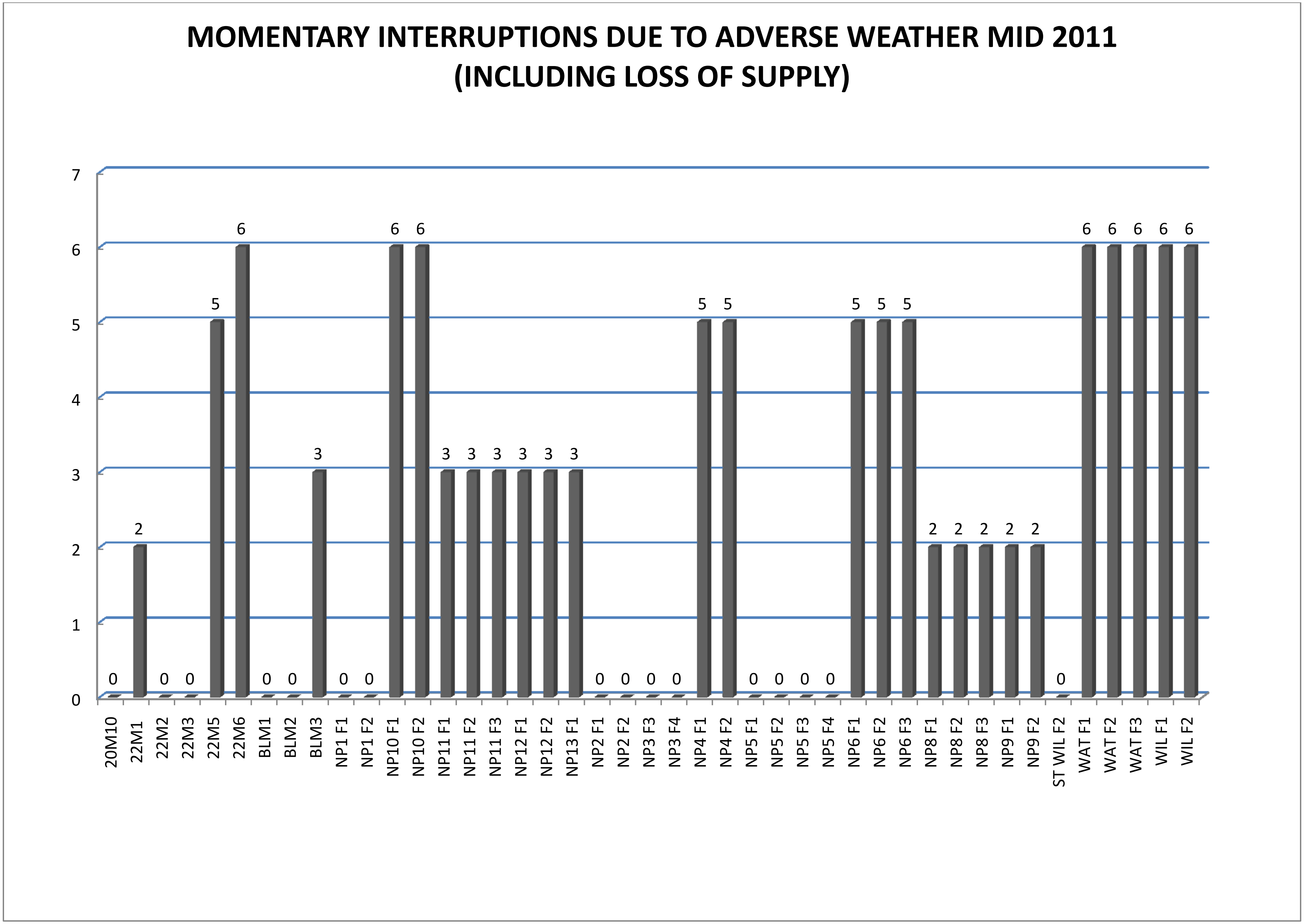
Jan 1, 2011 to June 30, 2011

NORFOLK POWER FEEDER PERFORMANCE RANKING 2011 JAN -JUN

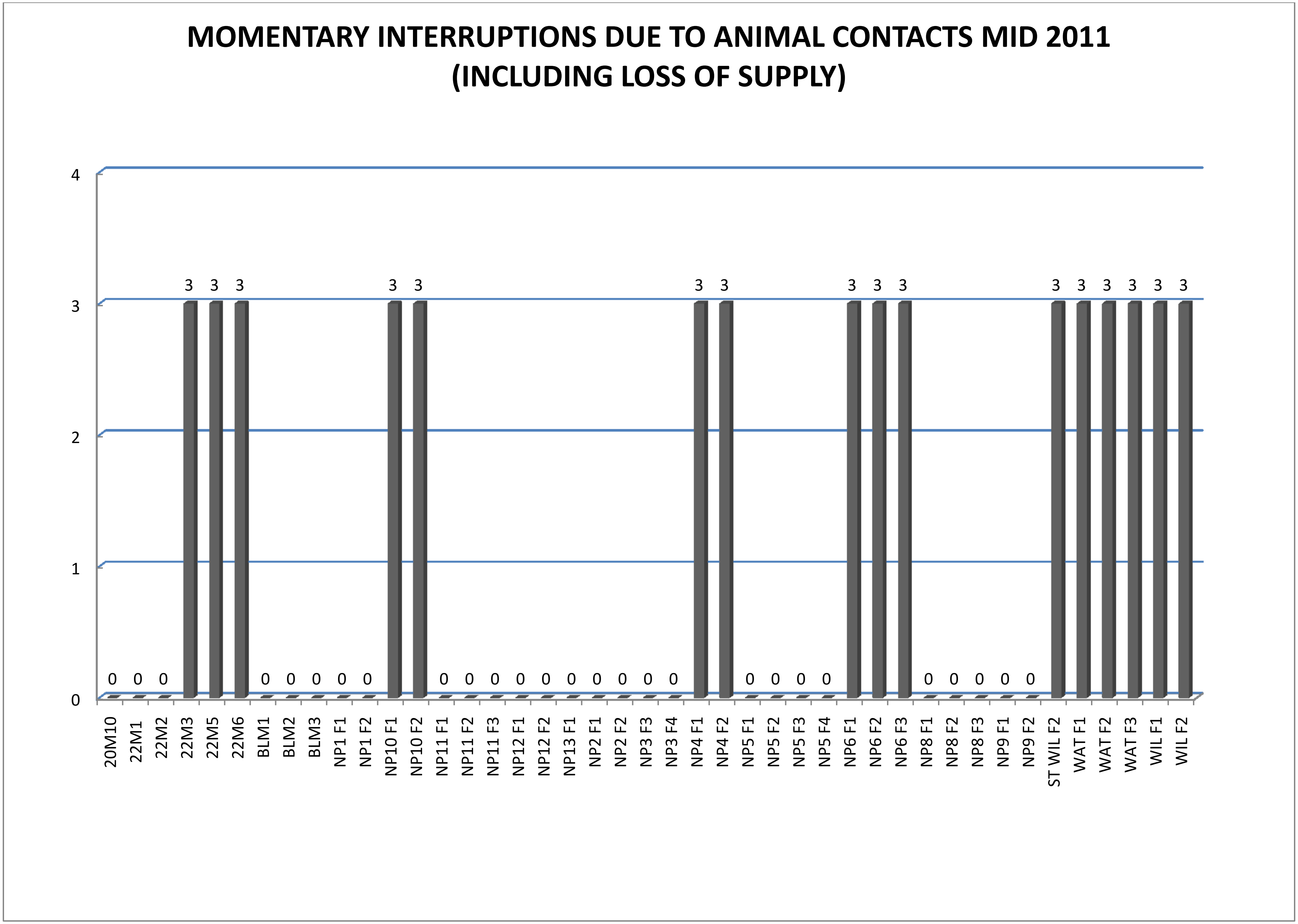
1ST WORST PERFORMING FEEDER	22M6	25 EVENTS
2ND WORST PERFORMING FEEDER	BLM3	19 EVENTS
3RD WORST PERFORMING FEEDER	22M5	12 EVENTS
4TH WORST PERFORMING FEEDER	BLM1	8 EVENTS
5TH WORST PERFORMING FEEDER	BLM2	6 EVENTS
6TH WORST PERFORMING FEEDER	NP4 F2	5 EVENTS
7TH WORST PERFORMING FEEDER	22M3	4 EVENTS
8TH WORST PERFORMING FEEDER	NP11 F1	4 EVENTS
9TH WORST PERFORMING FEEDER	NP8 F1	3 EVENTS
10TH WORST PERFORMING FEEDER	NP2F1	4 EVENTS

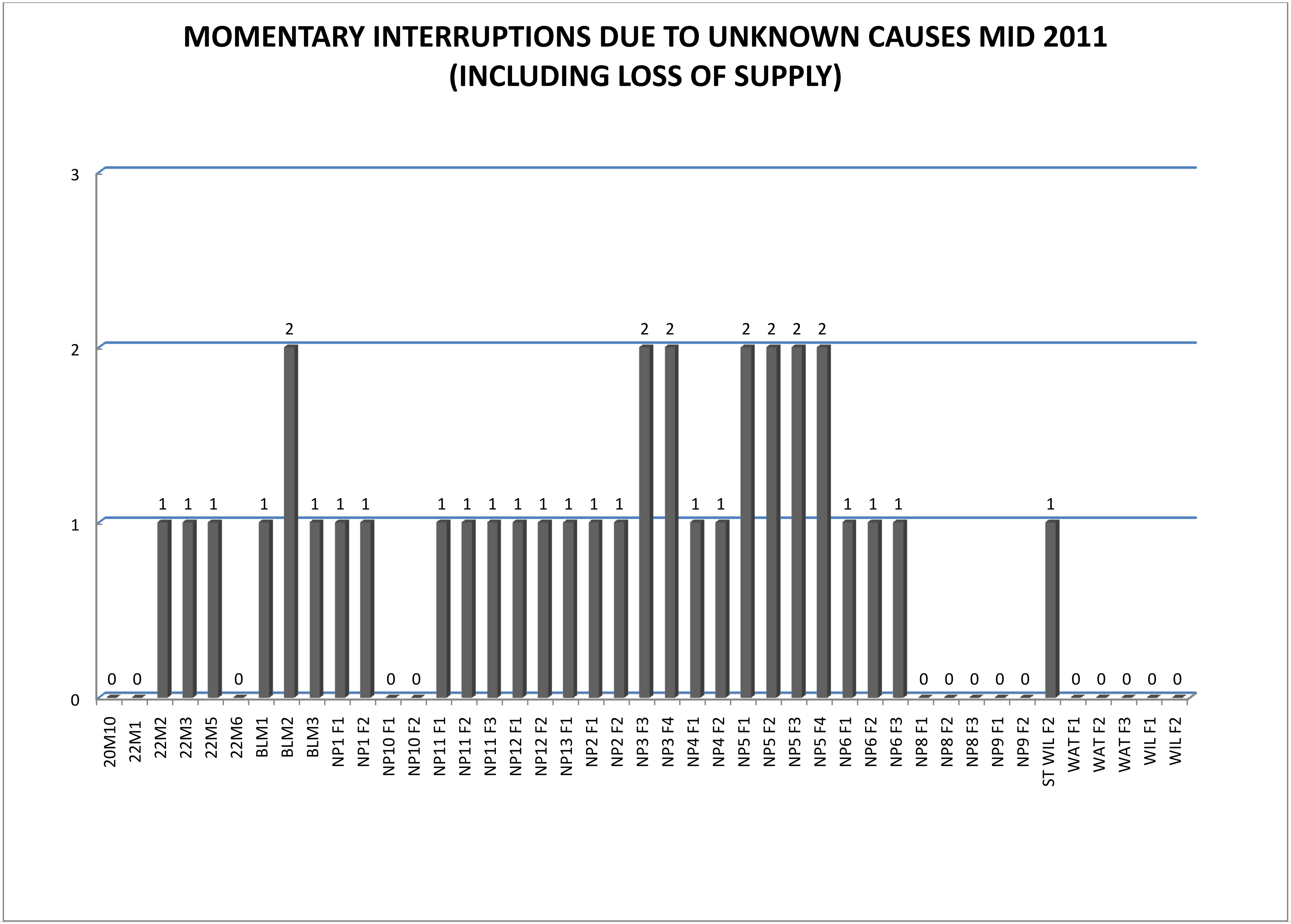


MOMENTARY INTERRUPTIONS MID 2011
(INCLUDING LOSS OF SUPPLY)
10
9
8
7
6
5
4
3
2
1
0
0
2
2
4
8
9
1
2
4
1
1
9
9
4
4
4
4
4
4
1
1
2
2
8
8
2
2
2
2
8
8
8
3
2
2
2
2
4
9
9
9
9
9
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2

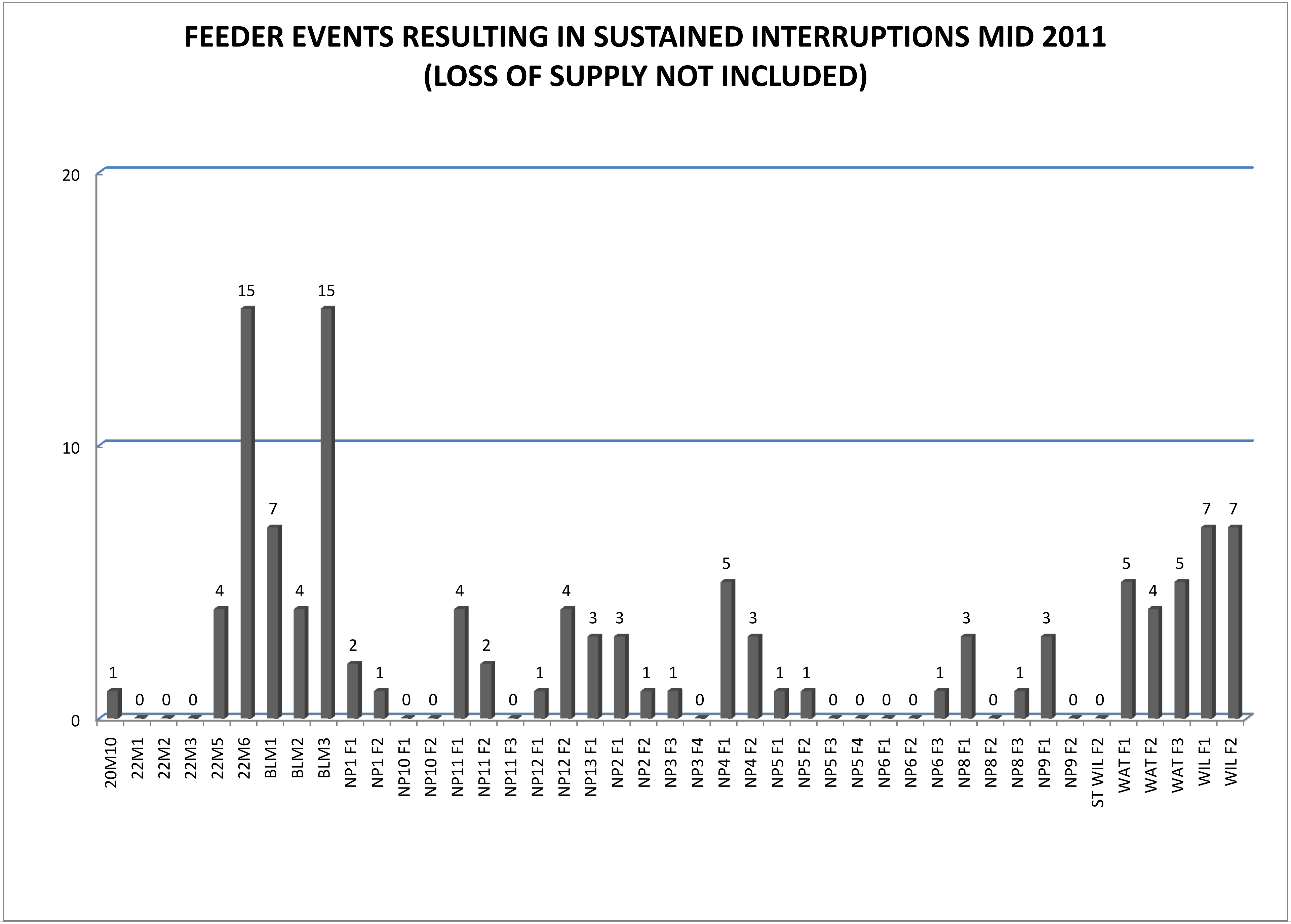


MOMENTARY INTERRUPTIONS DUE TO ADVERSE WEATHER MID 2011
(INCLUDING LOSS OF SUPPLY)
7
6
5
4
3
2
1
0
0 2 0 0 5 6 0 0 3 0 0 6 6 3 3 3 3 3 3 0 0 0 0 5 5 0 0 0 0 5 5 5 2 2 2 2 2 0 6 6 6 6 6
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2

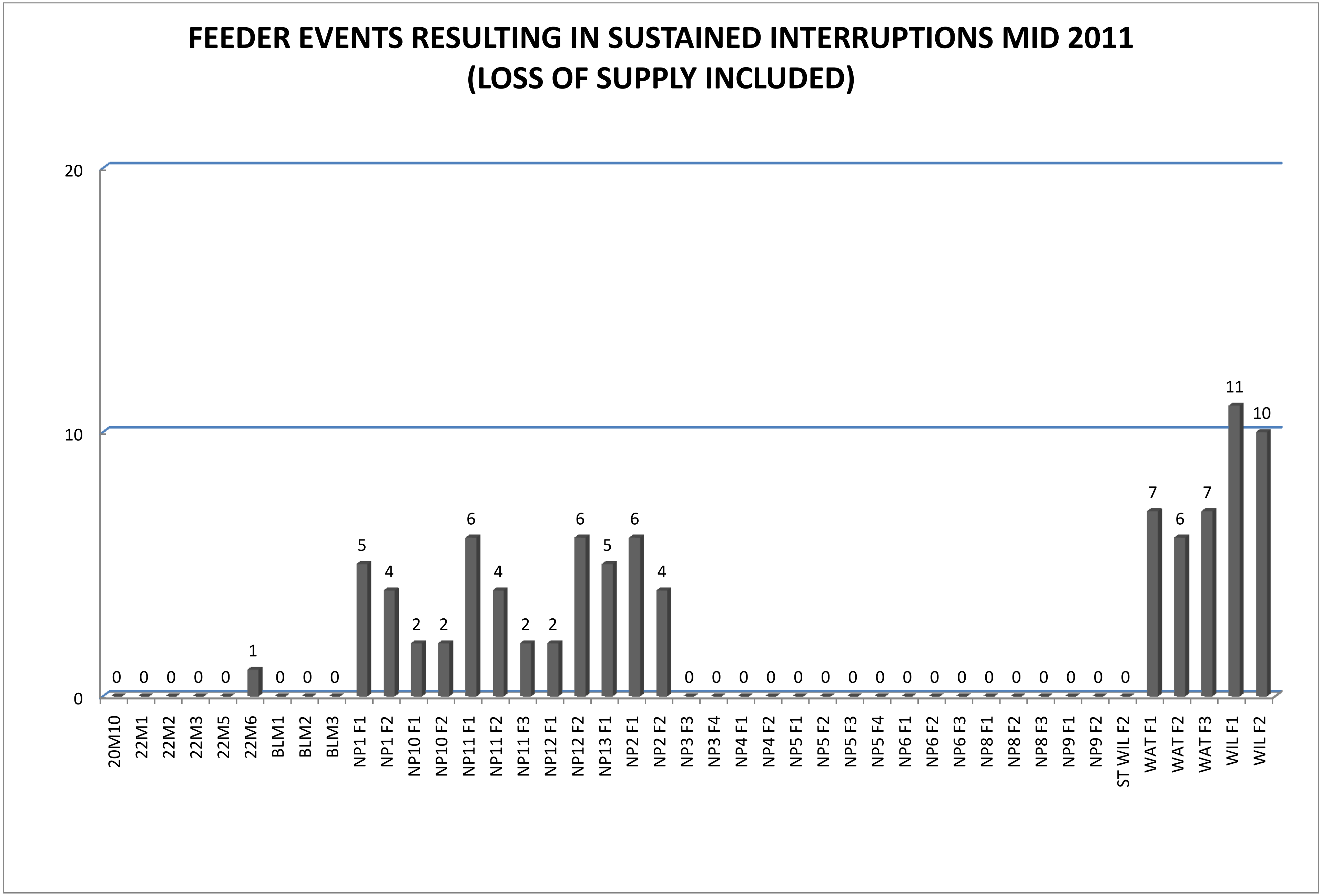

MOMENTARY INTERRUPTIONS DUE TO ANIMAL CONTACTS MID 2011
(INCLUDING LOSS OF SUPPLY)
0
1
2
3
4
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2
0 0 0 3 3 3 0 0 0 0 0 3 3 0 0 0 0 0 0 0 0 0 0 3 3 0 0 0 0 3 3 3 0 0 0 0 0 3 3 3 3 3 3



MOMENTARY INTERRUPTIONS DUE TO UNKNOWN CAUSES MID 2011
(INCLUDING LOSS OF SUPPLY)
3
2
1
0
0 0 1 1 1 0 1 2 1 1 1 0 0 1 1 1 1 1 1 1 1 2 2 1 1 2 2 2 2 1 1 1 0 0 0 0 0 1 0 0 0 0 0
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2



FEEDER EVENTS RESULTING IN SUSTAINED INTERRUPTIONS MID 2011
(LOSS OF SUPPLY NOT INCLUDED)
20
10
0
1 0 0 0 4 15 7 4 15 2 1 0 0 4 2 0 1 4 3 3 1 1 0 5 3 1 1 0 0 0 0 1 3 0 1 3 0 0 5 4 5 7 7
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


FEEDER EVENTS RESULTING IN SUSTAINED INTERRUPTIONS MID 2011
(LOSS OF SUPPLY INCLUDED)
20
10
0
0 0 0 0 0 1 0 0 0 5 4 2 2 6 4 2 2 6 5 6 4 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 7 6 7 11 10
20M10
22M1
22M2
22M3
22M5
22M6
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
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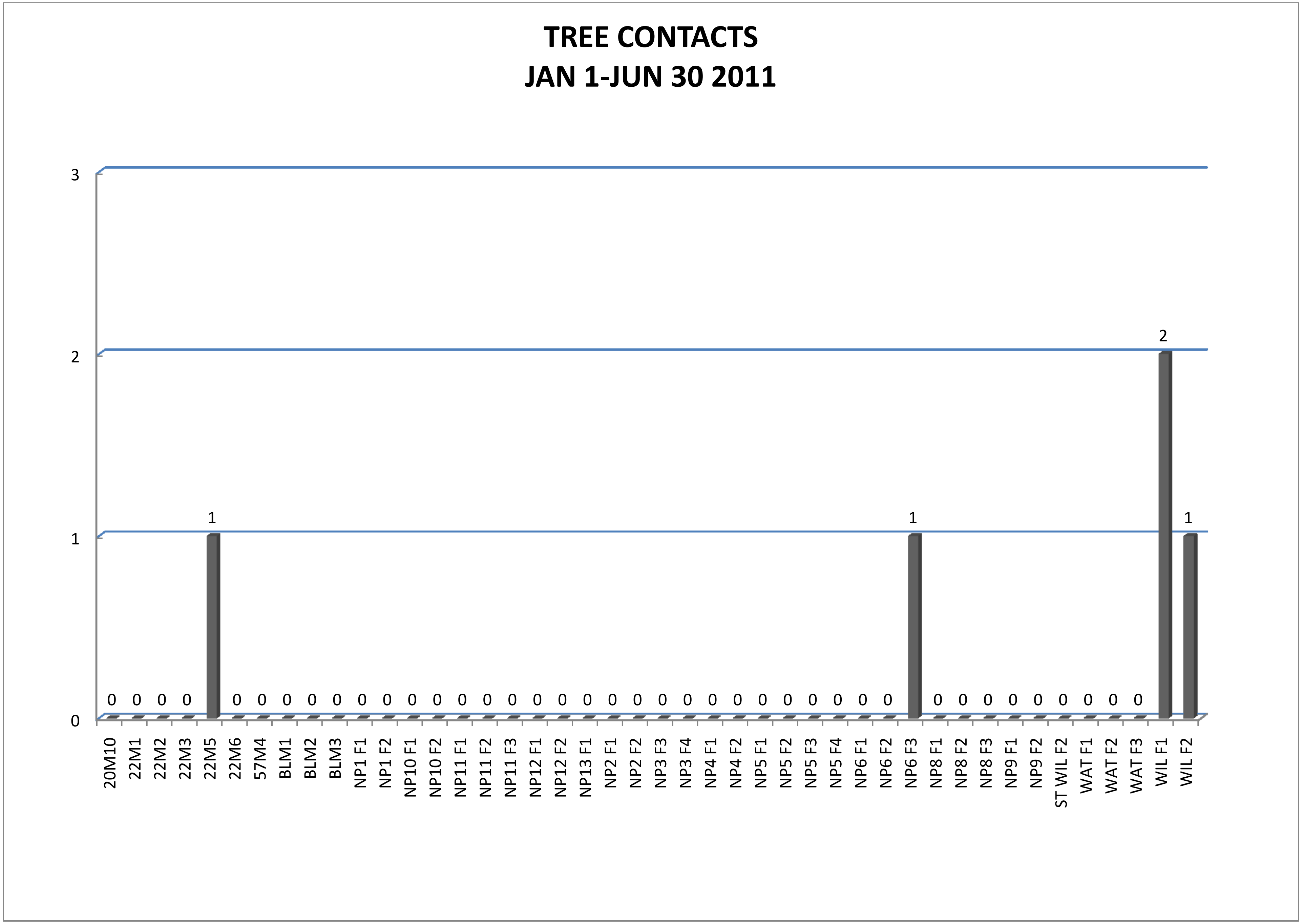
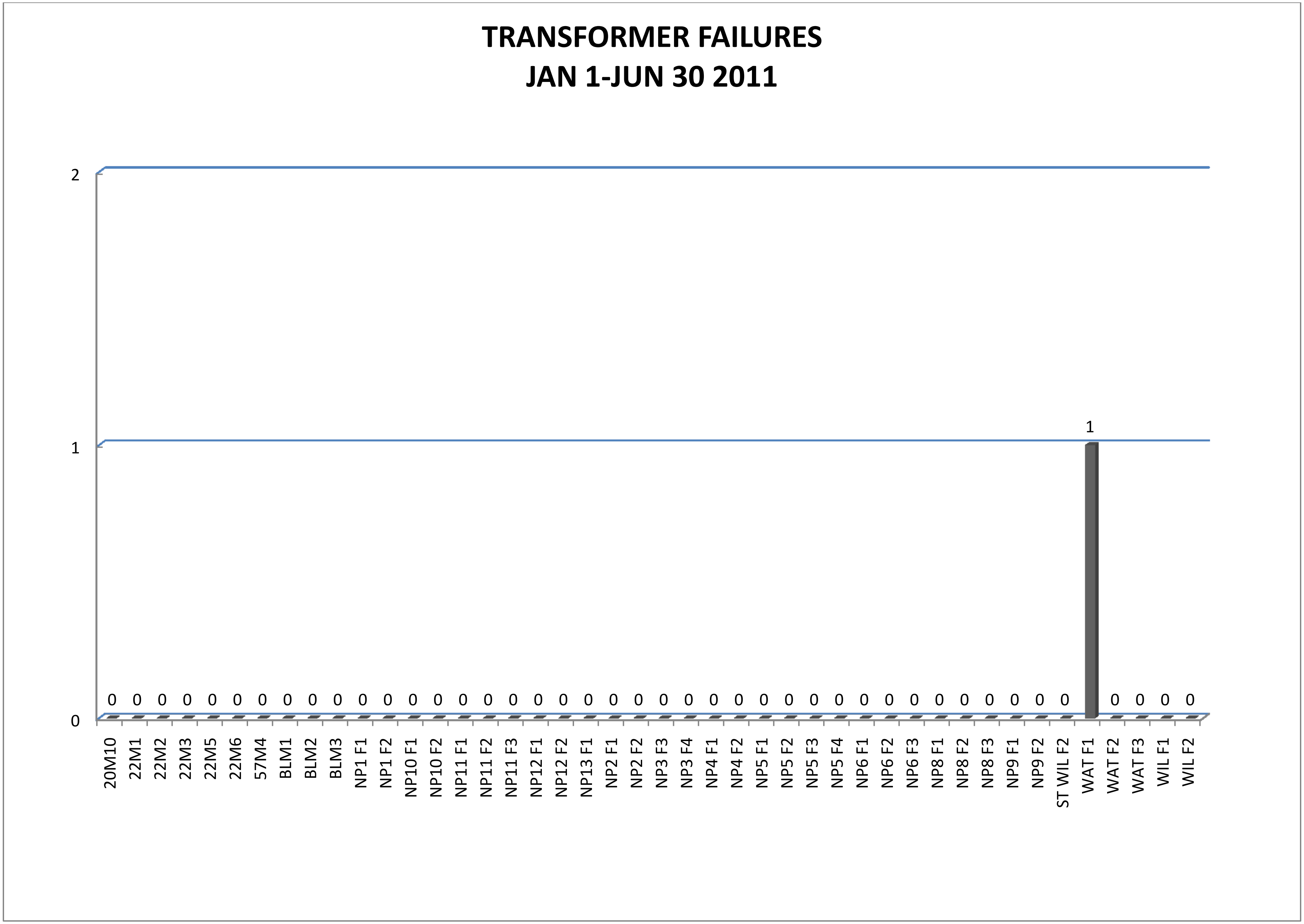
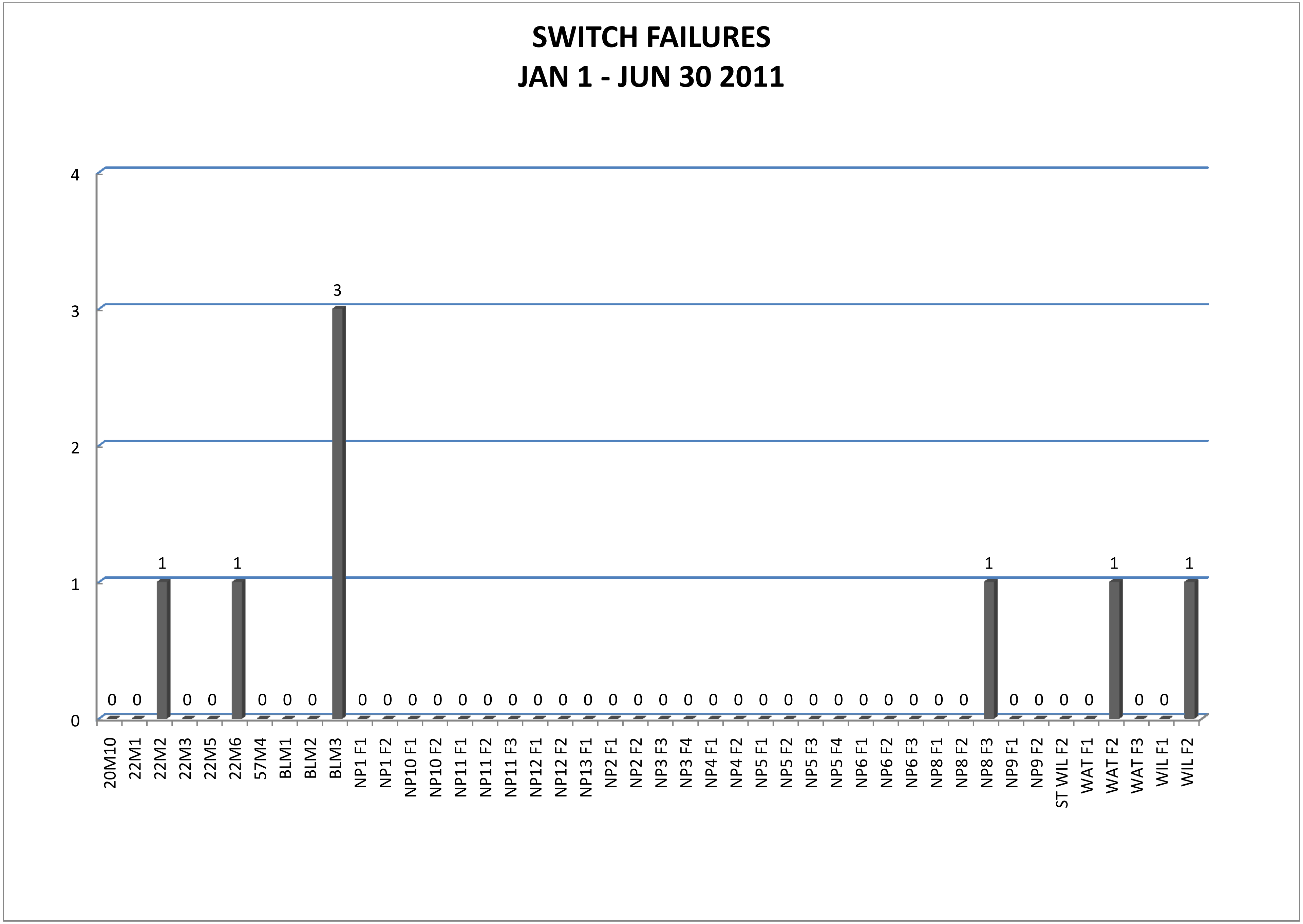
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


TREE CONTACTS
JAN 1-JUN 30 2011
3
2
1
0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2



TRANSFORMER FAILURES
JAN 1-JUN 30 2011
2
1
0
1
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
NP6 F3
NP8 F1
NP8 F2
NP8 F3
NP9 F1
NP9 F2
ST WIL F2
WAT F1
WAT F2
WAT F3
WIL F1
WIL F2


SWITCH FAILURES
JAN 1 - JUN 30 2011
4
3
2
1
0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
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NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
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NP5 F4
NP6 F1
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NP8 F1
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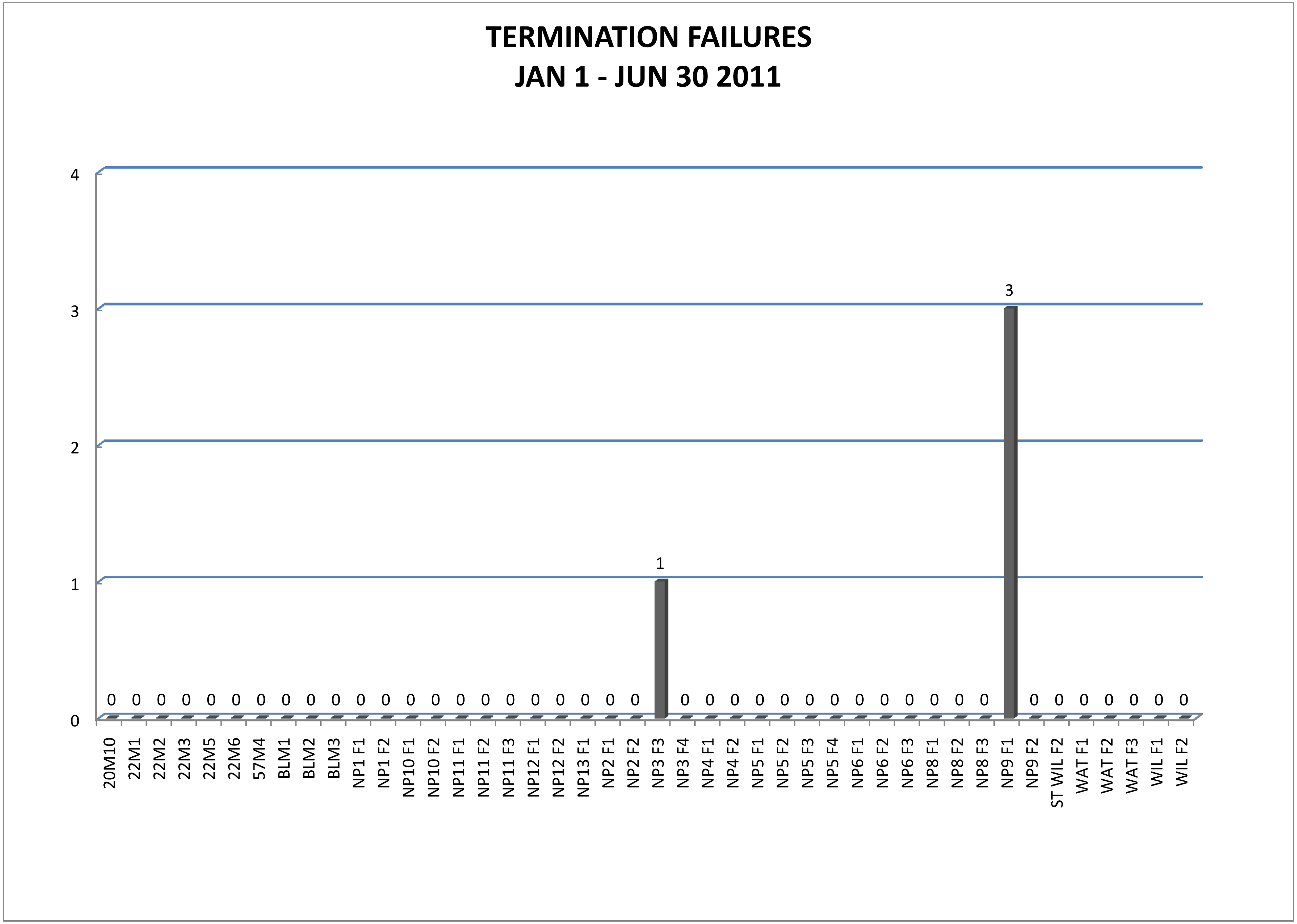

TERMINATION FAILURES
JAN 1 - JUN 30 2011
4
3
2
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20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
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BLM3
NP1 F1
NP1 F2
NP10 F1
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NP12 F1
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NP13 F1
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NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
NP6 F1
NP6 F2
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NP9 F1
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ST WIL F2
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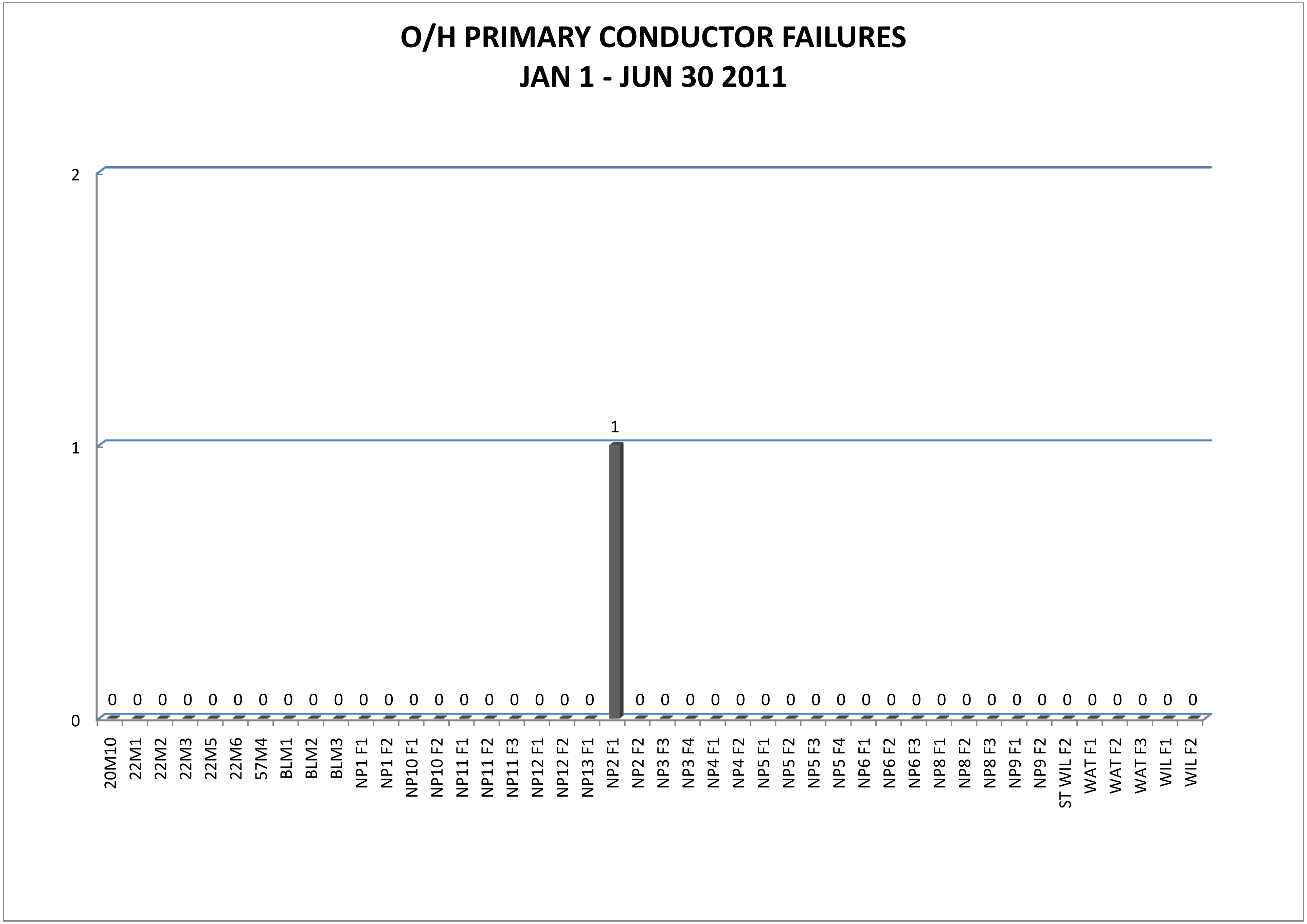
O/H PRIMARY CONDUCTOR FAILURES
JAN 1 - JUN 30 2011
2
1
0
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0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
20M10
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22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
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NP1 F1
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NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
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NP5 F4
NP6 F1
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NP6 F3
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NP9 F1
NP9 F2
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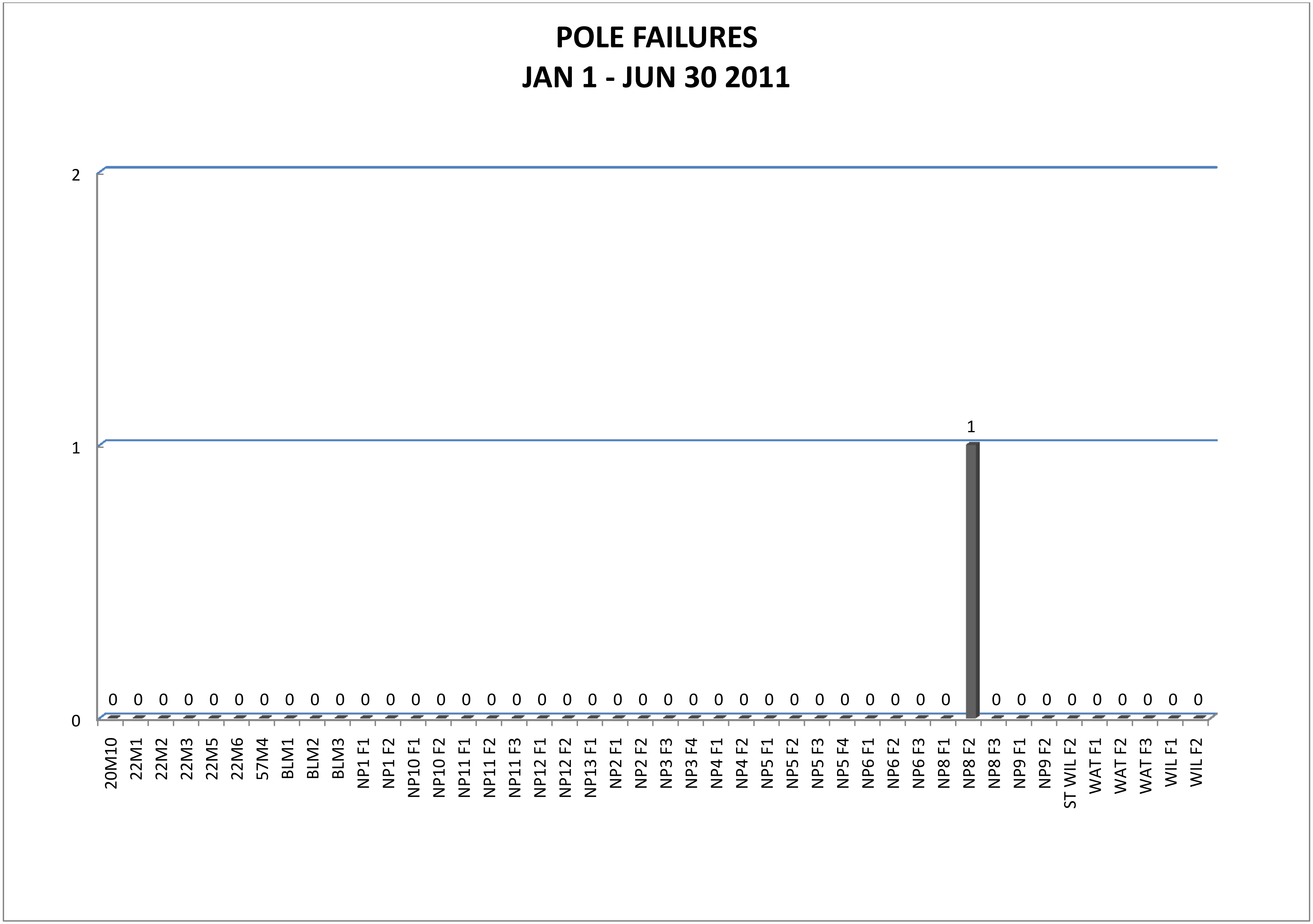
POLE FAILURES
JAN 1 - JUN 30 2011
2
1
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0
20M10
22M1
22M2
22M3
22M5
22M6
57M4
BLM1
BLM2
BLM3
NP1 F1
NP1 F2
NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
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NP4 F1
NP4 F2
NP5 F1
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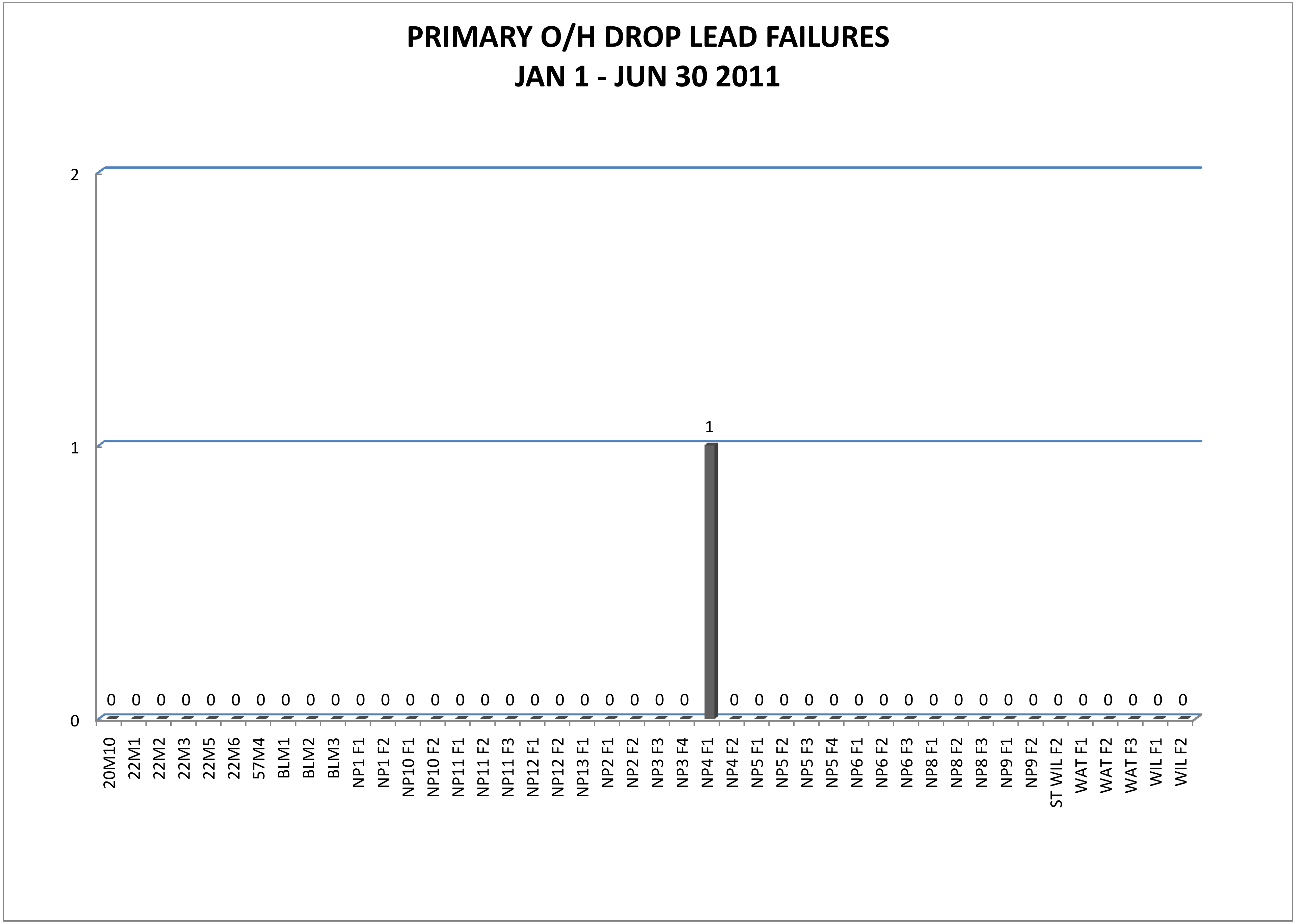
PRIMARY O/H DROP LEAD FAILURES
JAN 1 - JUN 30 2011
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0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
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NP1 F1
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NP10 F1
NP10 F2
NP11 F1
NP11 F2
NP11 F3
NP12 F1
NP12 F2
NP13 F1
NP2 F1
NP2 F2
NP3 F3
NP3 F4
NP4 F1
NP4 F2
NP5 F1
NP5 F2
NP5 F3
NP5 F4
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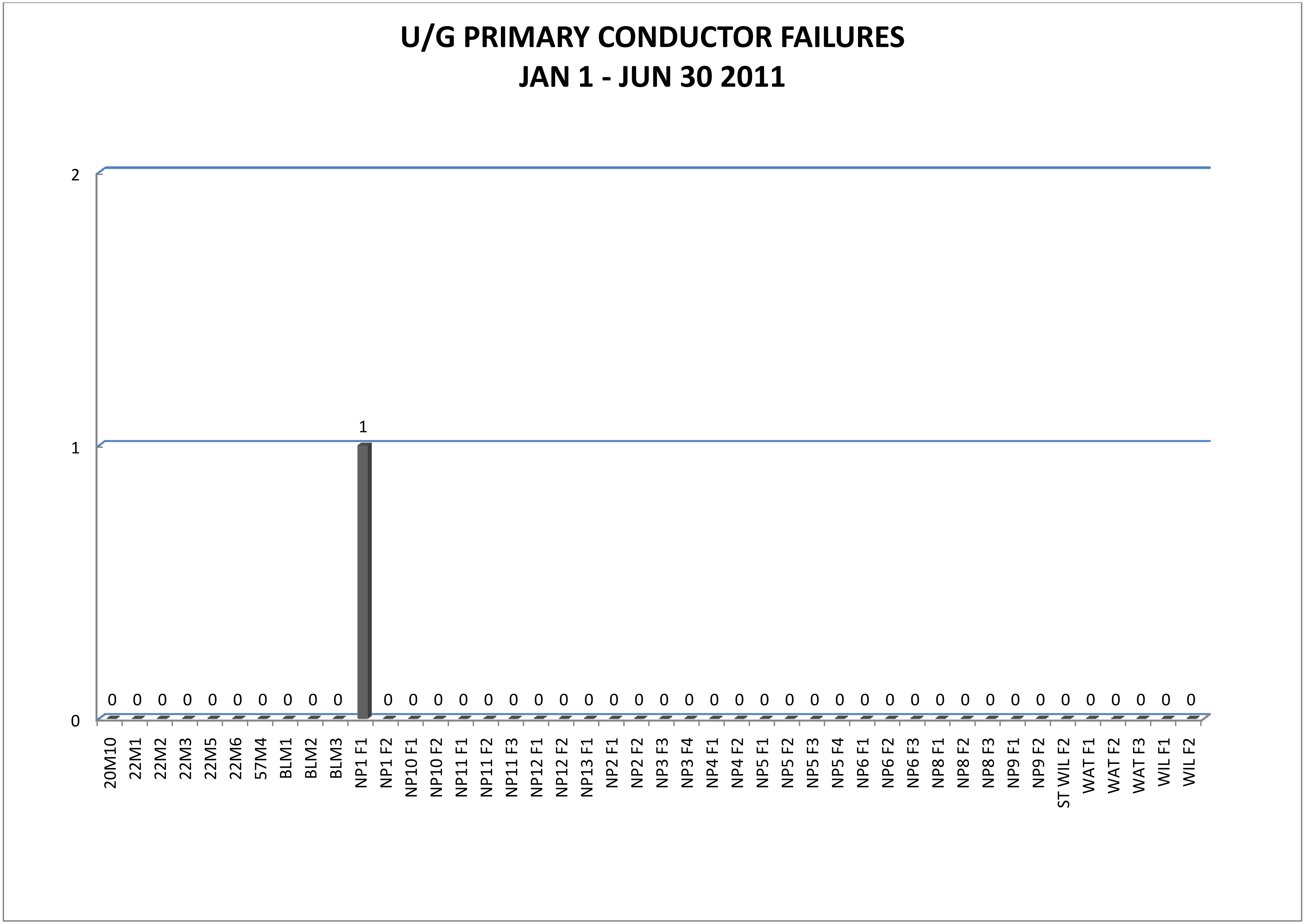
U/G PRIMARY CONDUCTOR FAILURES
JAN 1 - JUN 30 2011
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0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
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NP12 F1
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NP13 F1
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NP3 F3
NP3 F4
NP4 F1
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NP5 F1
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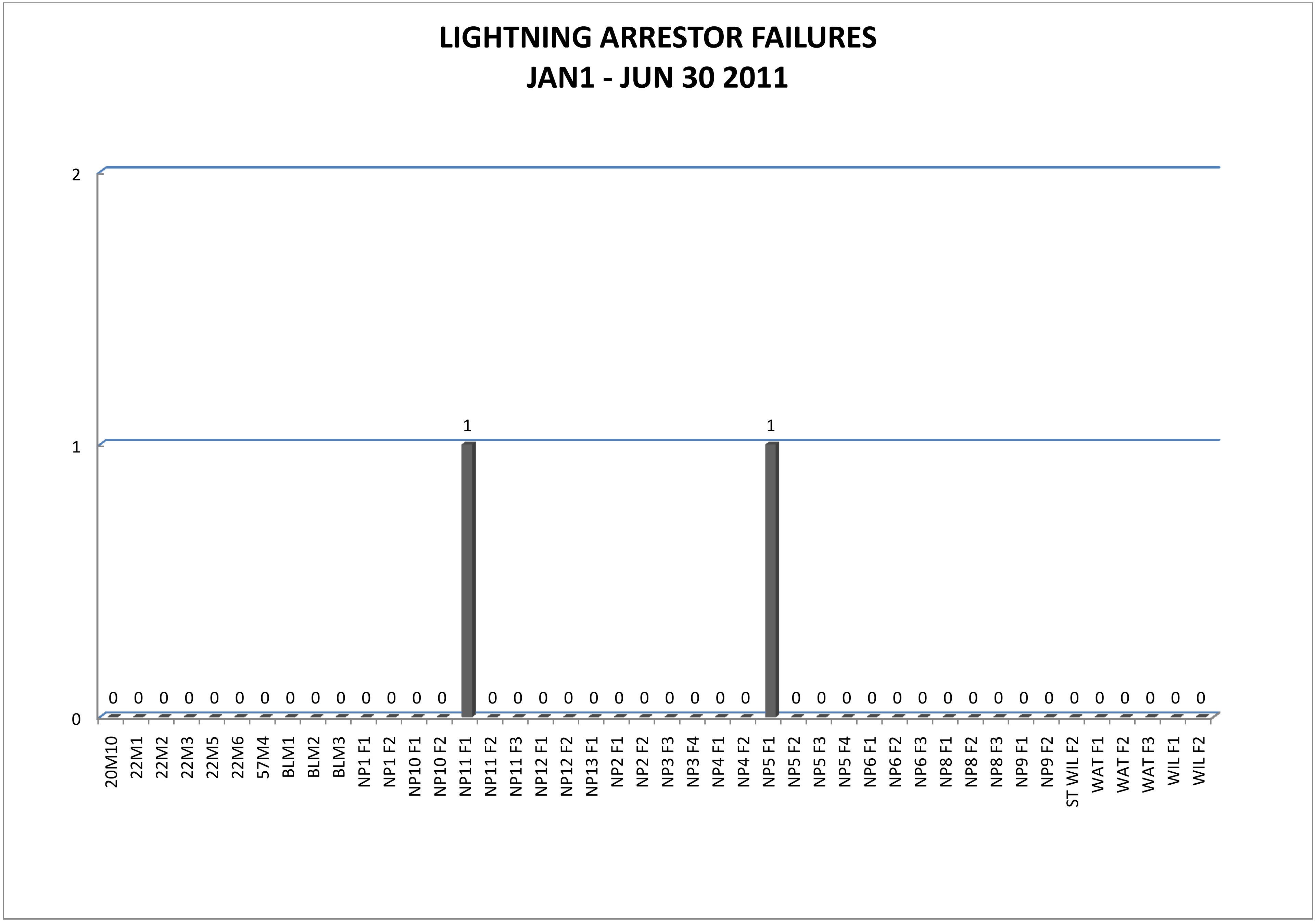
LIGHTNING ARRESTOR FAILURES
JAN1 - JUN 30 2011
2
1
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1
1
20M10
22M1
22M2
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22M5
22M6
57M4
BLM1
BLM2
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NP1 F1
NP1 F2
NP10 F1
NP10 F2
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NP13 F1
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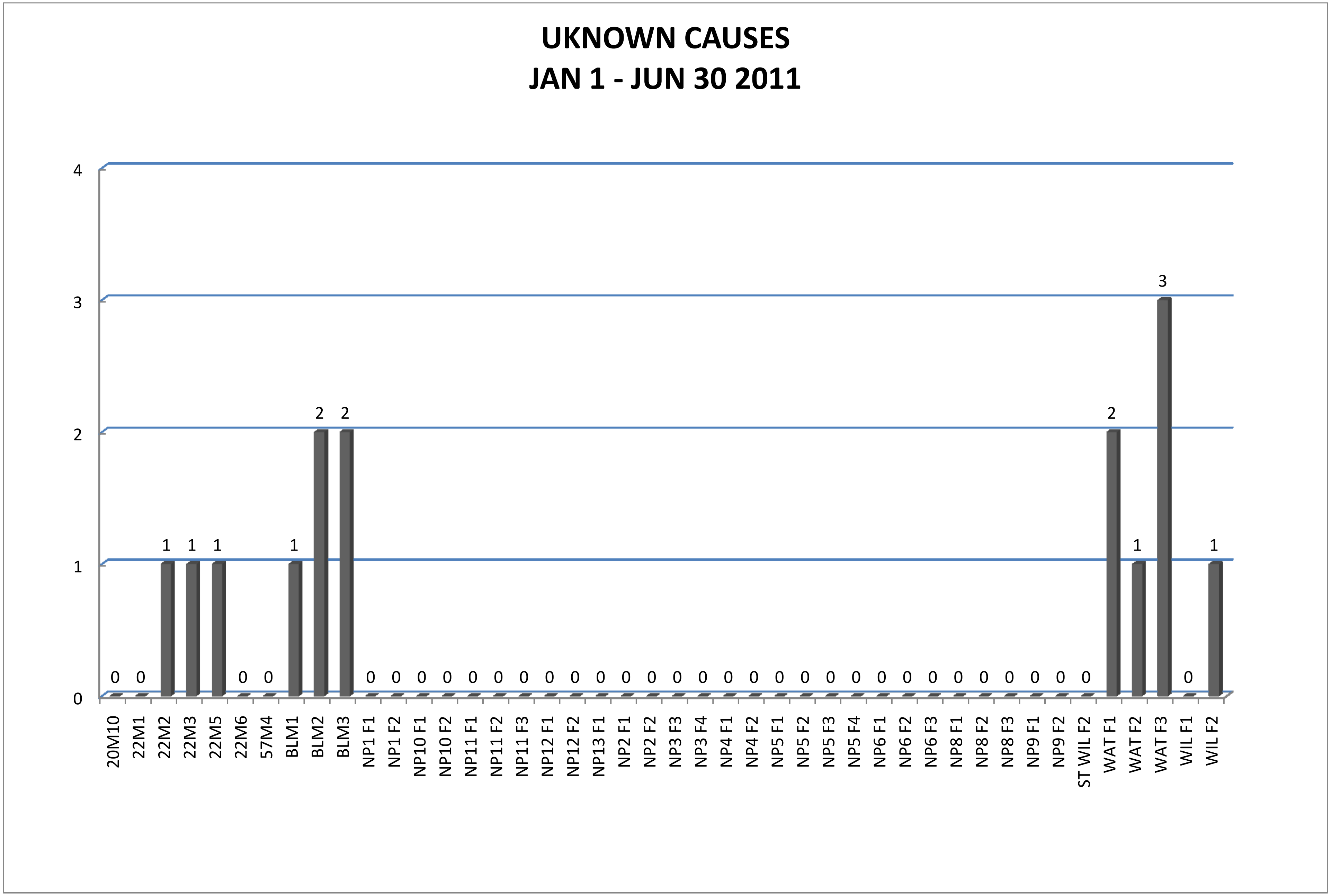
UKNOWN CAUSES
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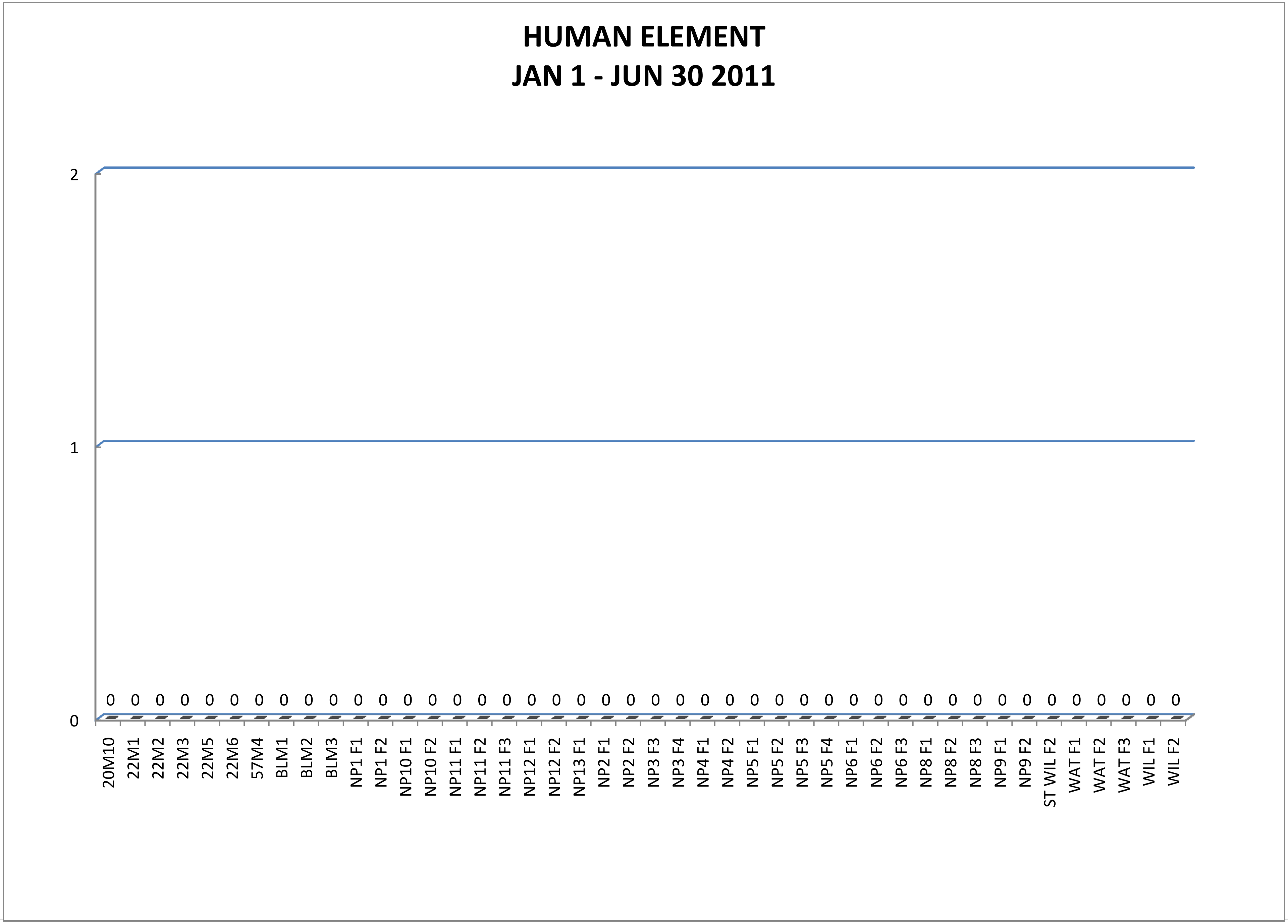
HUMAN ELEMENT
JAN 1 - JUN 30 2011
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NP9 F2
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FEEDER EVENT SUMMARY JAN 1 – JUN 30 2011

FEEDER	ADVERSE ENVIRONMENT-FIRE	ADVERSE WEATHER	HIGH WINDS	LIGHTNING	ANIMAL	BIRD	RACCOON	SQUIRREL	DIG IN	VEHICLE	IRRIGATION CANNON	HUMAN ELEMENT	LOSS OF SUPPLY	TREE CONTACT	UNKNOWN	ARRESTOR FAILURE	DROP LEAD FAILURE	POLE FAILURE	PRIMO/H CONDUCTOR FAILURE	PRIM U/G CONDUCTOR FAILURE	SEC O/H CONDUCTOR FAILURE	SWITCH FAILURE	TERMINATION FAILURE	TRANSFORMER FAILURE	SCORE
20M10		1																							1
22M1				2																					2
22M2															1							1			2
22M3							3								1										4
22M5		1	3	2			3			1				1	1										12
22M6		2	1	10	3		4	2			1		1									1			**25**
BLM1			4		1			1		1					1										8
BLM2			1	2				1							2										6
BLM3			5	7			1					1			2							3			19
NP1 F1			1										4							1					2
NP1F2			1							1			8												1
NP2 F1			1							1			8						1						3
NP2 F2			1										4												1
NP3 F3													2										1		1
NP3 F4													2												0
NP4 F1			4										5				1								5
NP4 F2			2							1			8												3
NP5 F1													2			1									1
NP5F2			1										2												2
NP5 F3													2												0
NP5F4													2												0

FEEDER	ADVERSE ENVIRONMENT-FIRE	ADVERSE WEATHER	HIGH WINDS	LIGHTNING	ANIMAL	BIRD	RACCOON	SQUIRREL	DIG IN	VEHICLE	DEBRIS IN PRIMARY	HUMAN ELEMENT	LOSS OF SUPPLY	TREE CONTACT	UNKNOWN	ARRESTOR FAILURE	DROP LEAD FAILURE	POLE FAILURE	PRIMO/H CONDUCTOR FAILURE	PRIM U/G CONDUCTOR FAILURE	SEC O/H CONDUCTOR FAILURE	SWITCH FAILURE	TERMINATION FAILURE	TRANSFORMER FAILURE	SCORE
NP6 F1													8												0
NP6 F2													8												0
NP6 F3													8	1											1
NP8 F1			3										2												3
NP8F2													2					1							1
NP8 F3													2									1			1
NP9 F1													2										3		3
NP9 F2													2												0
NP10 F1													11												0
NP10 F2													11												0
NP11 F1			3										6			1									4
NP11 F2			2										6												2
NP11 F3													6												0
NP12 F1			1										6												1
NP12 F2			3							1			6												4
NP13 F1			3										6												3

APPENDIX 8 – BOARD STAFF INTERROGATORIES

Benefact Report

BS IR#65)

BeneFACT
CONSULTING GROUP

Mr. Brad Randall
Norfolk Power Distribution Inc.
PO Box 588
70 Victoria Street
Simcoe, ON N3Y 4N6

June 20, 2011

Dear Mr. Randall,

We are pleased to inform you that your 2009 and 2010 Scientific Research & Experimental Development submissions have been completed. We have prepared both Federal and Ontario tax credit applications on your behalf.

According to our analysis your company is eligible for the following tax credit amounts:

Fiscal Year	Federal	Provincial	Total
2009	$ 152,049	$ 35,823	$ 187,872
2010	$ 62,282	$ 14,674	$ 76,956
		Total:	$ 264,828

Please be advised that your submissions are subject to review by the Canada Revenue Agency and the above amounts may be revised.

Attached please find copies of the following documentation:

- T661 – Claim for SR&ED carried out in Canada
- T661 Part 2 – Project Information
- T2 Schedule 31 – Investment Tax Credit – Corporations
- T2 Schedule 1 – Net Income (Loss) for Income Tax Purposes (Amended)
- T2 Schedule 5 – Tax calculations supplementary – corporations (Amended)
- T2 Schedule 508 (ON Sch. 508) – Ontario Research and Development Tax Credit
- RC59 – Federal Business Consent Form

The originals were prepared by BeneFACT and submitted to CRA for processing. Your accountant, Mr. Kevin Kitchen, received copies for his records as well.

To ensure prompt processing of your claim, please inform us immediately of any correspondence from CRA or requests for additional information.

Please feel free to contact us with any questions or concerns you may have.

Yours truly,

Victor Cucos

5060 Spectrum Way, Suite 400, Mississauga, ON L4W 5N5 Tel/Fax: (416) 360-7733 Toll Free: (855) TAX-BACK WWW.BENEFACT.CA

Canada Revenue Agency / Agence du revenu du Canada

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: Norfolk Power Distribution Inc.

Enter one of the following:

86289 2593 RC0001
Business Number (BN)

Social Insurance Number (SIN)

Tax year
From: 2009-01-01 (Year Month Day)
To: 2009-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 2

100 Contact person for the financial information: Rob Galipeau	**105** Telephone number/extension: (416) 360-7733	**110** Fax number: (416) 360-7733
115 Contact person for the technical information: Brad Randall	**120** Telephone number/extension: (519) 426-4574	**125** Fax number: (519) 426-4514

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered no to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	279,447
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	279,447
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	335,109
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	614,556
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	614,556

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		614,556
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	27,655
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	586,901
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	586,901
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	586,901
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	614,556	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	181,512		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	796,068	512 =	
Deduct				
• provincial government assistance	513 –	35,823	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	760,245	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	760,245
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	760,245

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162). You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	810	+	279,447
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	198
Subtotal (line 810 minus 812)	814	=	279,249

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Name of Specified Employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) **816** +

Salary base (total of lines 814 and 816)	818	=	279,249

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818 x 65%)	820	=	181,512

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for all SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. Design and Development of a DESN Transformer Station	165,414		335,109
2. Design and Development of a Mobile Power Substation	114,032		
Total	279,446		335,109

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 279,447

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	
Technologists and technicians	634	2
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 X
3. completed Part 2 for each project X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . . . . ☐

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable X
3. retained documents to support the SR&ED expenditures you claimed X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 X

* Form T1145, *Agreement ta Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*
** Form T1146, *Agreement ta Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*
*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*
**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Brad Randall — Name of authorized signing officer of the corporation, or individual

Signature

170 2011-06-20 — Date

175 BeneFACT Consulting Group Inc. — Name of person/firm who completed this form

Part 2 - Project information (continued)

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Design and Development of a DESN Transformer Station

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2009-01 (Year Month)	2010-03 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility **228** 1 [X] Others, specify **229** Field Site

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [X]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

Dual Element Spot Network (DESN) is a concept that provides redundancy in the form of duplication for most station components. Any single component can fail without seriously affecting supply reliability, as the companion equipment is capable of carrying the total station load. Currently there is an increased supply provided through a transmission line upgrade, demand for power has grown and reliability has become a predominant issue, all of which were not pressing concerns when the station was first designed. Therefore, during the initial design, we included a single transformer with contingencies in place to deal with doubling to full DESN in the future. In order to interface the older transformer technology with available equipment, we needed to develop a series of communication systems, overcome design issues and installation limitations.

During the design and development of a DESN Transformer station, we achieved the following technological advancements:

Increased capacity (from 25 to 50 MW), improving maintenance, providing operating flexibility and increasing reliability in power distribution.

Develop a transformer station system capable of assuming distributed generation.

A transformer with these specific requirements is not available from stock. We designed a functional device that can be integrated alongside existing

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

transformers containing older technologies to upgrade them to fully functional DESN stations.

We developed a unique dual supervisory and control system (SCADA) that can interface old and new technology enabling communication between components in transformer equipment to improve the reliability of the system and ultimately benefit the communities. According to our knowledge, this had never been done before in Ontario.

Development of a software solution that enabled communication between different technologies of various protection systems, i.e. breakers and switch gear.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The development, integration and testing of a DESN transformer station was a significant challenge given that different technologies installed in the existing station had to interface seamlessly. The following technological challenges were identified:

We were involved in the design process to ensure that all the required features were not only included but matched the existing transformer. We were uncertain on whether we could design the new transformer incorporating the required changes.

The new breaker technology installed in this transformer is configured differently from the original breakers, including changes in the way they vent, connect and operate.

The breaker failure protection and control software of the old transformer is PC based and was not available in the market anymore. We were uncertain how to interface that failure protection and control to the new breakers which work on a proprietary SEL platform.

Communication between every component in each of the two transformers and remote control stations needs to occur seamlessly. SCADA from the older transformer was programmed in DOS and while the new one was Windows based. We were uncertain how to achieve seamless communication between the components and control station.

Provisions to ensure the seamless incorporation of distributed generation were needed. However, distributed generation involves feeds at different voltage levels and an understanding of the type and size of local generation trends is crucial. We were uncertain how to accommodate for the many different possibilities.

The configuration of the feed from the power lines to the transformer station was radial. We were uncertain how to configure the new bus connection in order to accommodate the requirements of both transformers and the two different incoming feeds.

The size and load distribution of the new transformer had to be very similar to prevent issues with balance and support. We were uncertain whether the new technologies being used in the transformer would allow for size and load distribution.

We were uncertain about the best way to move it from the truck onto the pad due to the big difference in ground potential.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

The DESN transformer station is at the heart of the planning philosophy in Ontario. In order to guarantee that the transformer met the requirements we monitored its design and construction. The station s original feed was radial and could not accommodate a second transformer. In order to complete the DESN station we re-configured the feed busses. We had to guarantee that the double feed was in sync with the transformer design. The feed was changed but review of the calculations during the feed construction proved that changes to the

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

transformer s secondary were needed.

The installation of the transformer was done with the station operational to feed existing customers. Due to the transformer's large size and heavy weight, best practices include rolling, sliding and an engineered lift (crane) to move the transformer off the truck and onto the pad. We decided to use the crane due to the narrow space and the size of peripherals. The use of a crane presented a serious concern given the big difference in ground potential between inside and outside of the station. Additional grounding to the crane was added to ensure a safe working environment.

To utilize the concrete pad where the transformer sits, not only the external shape must be similar to the design of the old transformer but the peripherals and interior components must be arranged in a way that distributes the load evenly. The latter posed the most challenges due to the recent changes in the transformer components. In an attempt to distribute the loads evenly in the restricted space, we changed the location and size of oil container, and geometry of primary and secondary bushings. If the load distribution is not even, it can create distortion on the transformer`s frame that can lead to structural problems. Even with all the precautions taken, some distortion was evident as a small gap was seen underneath the transformer. Tests and calculations showed that it was within acceptance levels.

New breaker technology changed the way breakers function and are installed. New vent locations required a re-assessment of the breaker location and surrounding equipment to allow for correct cooling and reduce the magnetic interaction with other equipment. Considering the limited space available we determined that they would fit as is; however, during installation the breaker wouldn't connect to the existing hardware. We tried to use the original connectors but the tolerances were off and the electrical connection was not effective. In an attempt to solve this we modified connectors.

Breaker failure protection (relays) need to communicate and interact between each other and with the other transformer in the DESN station. We realized that the available protection system had changed since the previous transformer was installed and currently operates under a proprietary SEL platform that has the processor integrated. Interfacing the two technologies required us to understand how the communication between the new protection works, to fit the incoming data to the proper channels and to fit the outgoing data so that the old protection receives it properly. The interface for those two technologies was nonexistent and we came up with a first approach to a solution.

The transformer switch gear also has its own protection system. The transfer trip protection in each transformer needs to interface with the other transformer and feed lines from two different grid systems. The new model of transfer trip protection that was implemented was completely new to us. Interconnecting the protections was complicated as they used different communication protocols. Re-routing of the output signals was found to be a viable solution.

Communication between components in both transformers of the DESN station as well as with the remote control stations is carried over SCADA software. We found that the SCADA in the old transformer was DOS based and could not directly be interfaced with the new transformer s Windows based SCADA. We had never before dealt with an interfacing challenge like this. In an attempt to enable the communication between transformers we developed a dual station that receives data from each unit and converts it before sending it to the next

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

66. unit. By doing this we increased the processing time by a fraction of a
67. second, but it was a reliable solution.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project — **254** Name: Brad Randall

255 1 [ ] Other employee of the company — **256** Name:

257 1 [X] External consultant — **258** Name: Benefact Consulting — **259** Firm: Benefact Consulting

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Rod McDonald	Station Supervisor; 35+ years industry experience
2	Bruno Ciccotello	VP Engineering; 30+ years industry experience
3	Brad Randall	P. Eng - 25+ years industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? .... 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? .... 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? .... 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	B.G. High Voltage Systems Limited	10050 0727 RC0001

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents
271 1 [X] Records of resources allocated to the project, time sheets
272 1 [ ] Design of experiments
273 1 [ ] Project records, laboratory notebooks
274 1 [ ] Design, system architecture and source code
275 1 [ ] Records of trial runs
276 1 [X] Progress reports, minutes of project meetings
277 1 [ ] Test protocols, test data, analysis of test results, conclusions
278 1 [ ] Photographs and videos
279 1 [ ] Samples, prototypes, scrap or other artefacts
280 1 [X] Contracts
281 1 [X] Others, specify **282** Design Drawings

Part 2 - Project information (continued)

Project number 2

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Design and Development of a Mobile Power Substation

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2009-01 (Year Month)	2010-03 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project   **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes   2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory   **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility   **228** 1 [X] Others, specify **229** Field Site

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [X]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

Our power distribution network includes over 12 sub-stations supplying 50 feeders with different primary and secondary voltages. When any of these stations has an unexpected failure or a programmed maintenance shut down; the serviced area feels the impact. We determined that a mobile unit capable of swapping in for an out of service transformer was a required technological advancement. The following technological advancements were achieved during this project:

Development a substation mobile unit capable of being put into service in less than 1 hour after arriving at the desired location.

Development of a transformer that is capable of converting power between several voltage values and feeding multiple circuits with different voltage levels

Development of a viable sub-station that can be transported on existing road networks, for example, under bridges.

Reduce the need to use dedicated grounding for the transformer when in service.

Development of a transportation system capable of managing the size, weight and high center of gravity of this unit.

These advancements have reduced the time that communities are without power after a failure of a sub-station and allow for easier maintenance to our

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

sub-station system.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The development of a mobile substation unit presented technological difficulties that went beyond the current level expertise at Norfolk Power. Based on our knowledge, this was the first time a mobile sub-station was developed in Ontario. We identified the following technological challenges:

We required a transformer that could be put into service as soon as it arrives to the location; however, commercial mobile transformers of similar capacity require a period of at least 24 hours before they can be put into service. We were uncertain on how to achieve this fundamental characteristic.

Power distribution is usually done at 13.8kV, 28kV or 44kV therefore the mobile transformer has to be able to receive this feed through the primary and produce a range between 3and5 kV in the secondary. We were uncertain whether such range of transformation was possible given the size and weight limitations.

We were uncertain how to connect the transformer to the feed and distribution busses. Stationary transformers use bare aerial conductors to connect to the bus; however, a mobile system requires an insulated and flexible conductor. These two properties are not easy to match for such conductor diameters.

The internal components of a transformer don t tolerate constant movement and the bumps of the road especially for a device this large (60 tons). We were uncertain how to produce a device with strong enough components to endure this treatment.

Grounding is crucial for any electrical system; and it is critical for a device working at higher voltages for safety reasons. We were uncertain on how to produce a grounding system capable to operate from a mobile unit.

Mobility was a serious issue; no commercial trailer was available for the heavy weight and height clearance needed neither a flatbed nor a regular lowboy semitrailer were viable options for transportation of this transformer. The height and width limits in bridges, sub-stations and service bays combined with its high center of gravity makes it very challenging to find or build a functional trailer. We were uncertain whether all the requirements could be met simultaneously.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

When an unexpected failure shuts down a sub-station, the equipment may remain inoperative for a few days even weeks leaving the affected area with limited power supply. In the same fashion, when a programmed maintenance is underway the affected area relies upon on-off supply from neighbouring stations. Our mobile unit is required to be operational within an hour of getting to location unlike most commercial mobile sub-stations that can't become operational before at least 24 hrs from arriving to location. The latter is due to a vacuum filled transformer which limits the device from being put in service. We developed a sealed conservative transformer tank that prevents the oil from entrapping air bubbles during the move. This special design allows getting the sub-station operational sooner; however, it is taller than the other conventional option.

The current technologies allow converting from the various possible primary voltages to alternative secondary voltages; however, the size and weight of the resulting equipment becomes unfit for a mobile unit. To overcome these restrictions we first attempted to develop a trailer with hydraulics that allowed using the maximum available height to build the transformer. Second we distributed many of the peripherals including the oil reservoir and in some

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

cases in such way that they could be removed for the road and quickly installed back once in location. Then we focused on reducing the size and weight of the internal components like the primary and secondary masses; most mobile units have a primary mass but for this one we were able to introduce a cable mobile primary as well as a particular type of relay and switching which is unique in many ways. These novel changes allowed accommodating the various voltages in the restricted space.

When connecting the transformer to the feed and distribution busses in commercial mobile sub-stations, it usually requires bare overhead conductors to and from the busses. In order to support rapid in-service of the transformer we researched into using insulated conductors that could be rolled and transported with ease. We tested several samples until we found the appropriate ones that were ultra flexible for the physical limitations at the sites and for storage. Another big issue we encountered was the different connectors available; we used hardware that was standard across the utility industry so that operators didn't need to familiarize with new hardware but still we faced issues since not all the stations use the same standards. We adapted connectors to act as conversion blocks for those stations.

We tested regular internal components for road conditions and found that they are prone to damage during transportation. The internals (coils and other components) of our mobile unit need be very robust so we ordered custom components with extra torque ratios to reduce the risk of damage from the road transportation. We noted that the bus atop of the transformer also had to be upgraded in order to withstand the road beating and sealed to prevent water seeping into it. The system was tested on the roads several times and the performance was not affected.

Grounding is a big issue anywhere high voltage is used. Moreover in a mobile sub-station that does not have the standard buried grounding systems. To reduce the dependence of external grounding we used the massive mass that surrounds the equipment and available connections to the sub-station grounding; however, in some cases where the ground potential difference was still high we had to use dedicated grounding.

In order to utilize the maximum available height under bridges and entering the substations, we opted to use a lowboy semitrailer. The calculations however showed that the maximum leaning or turning momentum (critical for stability on the road) was difficult to control with the conventional lowboy semi. The trailer had to use hydraulics to compensate for the leaning of the transformer during transportation. This option also improved the stability of the system once on location as it could be rested on the ground.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project	**254** Name: Brad Randall
255 1 [ ] Other employee of the company	**256** Name:
257 1 [X] External consultant	**258** Name: Benefact Consulting — **259** Firm: Benefact Consulting

List the key individuals directly involved in the project and indicate their qualifications/experience.

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2 Bruno Ciccotello	VP Engineering; 30+ years industry experience
3 Brad Randall	P. Eng - 25+ years industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

- **270** 1 [X] Project planning documents
- **271** 1 [X] Records of resources allocated to the project, time sheets
- **272** 1 [ ] Design of experiments
- **273** 1 [ ] Project records, laboratory notebooks
- **274** 1 [ ] Design, system architecture and source code
- **275** 1 [ ] Records of trial runs
- **276** 1 [X] Progress reports, minutes of project meetings
- **277** 1 [ ] Test protocols, test data, analysis of test results, conclusions
- **278** 1 [ ] Photographs and videos
- **279** 1 [ ] Samples, prototypes, scrap or other artefacts
- **280** 1 [X] Contracts
- **281** 1 [X] Others, specify **282** Design Drawings

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and did not expire before 2008 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 **(consolidated)**, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 ______ x 10 % = 240

Credit allocated from a partnership 250

Subtotal

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures

Current expenditures (from line 557 on Form T661)		760,245		
Add:				
Contributions to agricultural organizations for SR&ED under paragraph 37(1)(a)*				
Deduct:				
Government and non-government assistance*				
Contributions to agricultural organizations for SR&ED*	▶			
Current expenditures (including contributions to agricultural organizations for SR&ED)*		760,245 ▶	350	760,245
Capital expenditures (from line 558 on Form T661)			360	
Repayments made in the year (from line 560 on Form T661)			370	
Total (this must equal the amount from line 570 on Form T661)*			380	760,245

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? ..... **385** 1 Yes [X] 2 No [ ]

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). ..... **390** ______

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return). ..... **395** ______

c) Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. ..... **398** ______

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1: Tax year ends before February 26, 2008.
[($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)] . . . . ______

Calculation 2: Tax year starts after February 26, 2008 and ends before January 1, 2010.
[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ______

Calculation 3: Tax year includes February 26, 2008.
AA + [(BB **minus** AA) x (CC **divided by** DD)] where,

- **AA** = [($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)];
- **BB** = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **CC** = number of days in the tax year after February 25, 2008;
- **DD** = number of days in the tax year. . . . . ______

Calculation 4: Tax year starts after December 31, 2009.
[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ______

Calculation 5: Tax year includes January 1, 2010.
EE + [(FF **minus** EE) x (GG **divided by** HH)] where,

- **EE** = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **FF** = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **GG** = number of days in the tax year after December 31, 2009;
- **HH** = number of days in the tax year. . . . . ______

Enter the amount from Calculation 1, 2, 3, 4 or 5, whichever is applicable ______ *G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ______ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ______ x Number of days in the tax year 365 / 365 = ... ______ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . . . **410** ______

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	760,245	x	20 %	=	152,049	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=		N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=			
480		x	20 %	=			
			Total			▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 152,049

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
Subtotal			▶
ITC at the beginning of the tax year		520	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540	152,049	
Credit allocated from a partnership	550		
Subtotal		152,049 ▶	152,049
Total credit available			152,049
Deduct:			
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	152,049	
Credit carried back to the previous year(s) (from Part 13)			P
Credit transferred to offset Part VII tax liability	580		
Subtotal		152,049 ▶	152,049
Credit balance before refund			Q
Deduct:			
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)		610	
ITC closing balance on SR&ED		620	

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12)		R		
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S		
Refundable credits (amount R or S, whichever is less)*				T
Amount J from Part 11		U		
Subtract: Amount T or U, whichever is less				V
Net amount (if negative, enter "0")				W
Amount W ____ x 40 %				X
Add: Amount V				Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)				Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)				AA
Amount J from Part 11		BB		
Subtract: Amount AA or BB, whichever is less				CC
Net amount (if negative, enter "0")				DD
Amount M from Part 11				EE
Amount DD or EE, whichever is less ____ x 40 %				FF
Add : Amount CC above				GG
Refund of ITC (amounts FF **plus** GG)				HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 ...... ______ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above ...... ______ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above ...... ______ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN ...... ______ OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . .

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired* 845

Subtotal ▶

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18 . . . . . 870 ______ x 10 % = ... 880

Total credit available . . . .

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures 890

* The credit is eligible for a 20 year carryforward effective for credits earned in 2003 and later tax years.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	
				Total (enter on line CCC in Part 19)		

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1.					
				Total current-year credit (enter at line 640)	

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . ______

Deduct:

Credit deemed as a remittance of co-op corporations . . . . **612** ______

Credit expired after 20 tax years . . . . **615** ______

Subtotal ______ ▶ ______

ITC at the beginning of the tax year . . . . **625** ______

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . **630** ______

ITC from repayment of assistance . . . . **635** ______

Total current-year credit (total of column 605) . . . . **640** ______

Credit allocated from a partnership . . . . **655** ______

Subtotal ______ ▶ ______

Total credit available . . . . ______

Deduct:

Credit deducted from Part I tax (enter on line B4 in Part 30) . . . . **660** ______

Credit carried back to the previous year(s) (from Part 23) . . . . ______ DDD

Subtotal ______ ▶ ______

ITC closing balance from apprenticeship job creation expenditures . . . . **690** ______

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day			
1st previous tax year				Credit to be applied	**931**	
2nd previous tax year				Credit to be applied	**932**	
3rd previous tax year				Credit to be applied	**933**	
				Total (enter on line DDD in Part 22)		

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year **715** ______ EEE

Add: Specified child care start-up expenditures from the current tax year . . . . . **705** ______ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . . **725** ______ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") ______ III

Add: Repayments of government and non-government assistance . . . . . **735** ______ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . . . **745** ______

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
	Subtotal		▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
	Subtotal		▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
	Subtotal		▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year / Month / Day			
1st previous tax year	2008-12-31	Credit to be applied	941	
2nd previous tax year	2007-12-31	Credit to be applied	942	
3rd previous tax year	2006-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - – disposed of or leased to a lessee; or
  - – converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	152,049	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)		B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	152,049	B6

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

AMENDED

	Line	Amount		Total	
Amount calculated on line 9999 from Schedule 125				2,088,028	A
Add:					
Provision for income taxes – current	101	912,000			
Amortization of tangible assets	104	2,881,007			
Scientific research expenditures deducted per financial statements	118	614,556			
Reserves from financial statements – balance at the end of the year	126	1,874,160			
Subtotal of additions		6,281,723	▶	6,281,723	
Other additions:					
Miscellaneous other additions:					
604					
Total	294				
Subtotal of other additions	199		▶		
Total additions	500	6,281,723	▶	6,281,723	
Deduct:					
Gain on disposal of assets per financial statements	401	10,030			
Capital cost allowance from Schedule 8	403	2,968,300			
Cumulative eligible capital deduction from Schedule 10	405	16,676			
SR&ED expenditures claimed in the year from Form T661 (line 460)	411	586,901			
Reserves from financial statements – balance at the beginning of the year	414	1,476,440			
Subtotal of deductions		5,058,347	▶	5,058,347	
Other deductions:					
Miscellaneous other deductions:					
700 Prior Period Adjustment	390	518,958			
704					
Total	394				
Subtotal of other deductions	499	518,958	▶	518,958	
Total deductions	510	5,577,305	▶	5,577,305	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				2,792,446	

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

AMENDED

Part 1 – Allocation of taxable income

100 ____________ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

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* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,792,446		2,792,446	348,442

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	390,942			
Deduct: Ontario small business deduction (from schedule 500)	402	42,500			
Subtotal (if negative, enter "0")		348,442	▶	348,442	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272	42,500			
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal		42,500	▶	42,500	B6
Subtotal (amount A6 **plus** amount B6)				390,942	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				390,942	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416	35,823	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				355,119	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				355,119	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	83,043			
Subtotal		83,043	▶	83,043	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				438,162	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal			▶		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	438,162	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	438,162

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2009-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	796,068 A			
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	B			
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		796,068 C			
Add: Eligible expenditures transferred to the corporation by another corporation	110	D			
Subtotal (amount C **plus** amount D)		796,068	▶		796,068 E
Deduct: Eligible expenditures the corporation transferred to another corporation				115	F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120	796,068 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)		796,068	x		4.50 % =	200	35,823 H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *						205	I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x		4.50 % =	215	J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220		x 1 / 4 =		x 4.50 % =	225	K
Current part of the ORDTC (total of amounts H to K)						230	35,823 L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			M	
Deduct: ORDTC expired after 20 tax years	**300**		N	
ORDTC at the beginning of the tax year (amount M **minus** amount N)	**305**		O	
Add:				
ORDTC transferred on amalgamation or windup	**310**		P	
Current part of ORDTC (amount L in Part 2)	35,823 Q			

Are you waiving all or part of the current part of the ORDTC? ...... **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	**320**	R		
Subtotal (amount Q **minus** amount R)	35,823	▶	35,823 S	
ORDTC available for deduction (total of amounts O, P and S)			35,823	▶ 35,823 T
Deduct:				
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			35,823 U	
ORDTC carried back to a previous tax year (from Part 4)			V	
Subtotal (amount U **plus** amount V)			35,823	▶ 35,823 W
ORDTC balance at the end of the tax year (amount T **minus** amount W)			**325**	X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year / Month / Day			
1st previous tax year	2008-12-31	Credit to be applied	**901**	
2nd previous tax year	2007-12-31	Credit to be applied	**902**	
3rd previous tax year	2006-12-31	Credit to be applied	**903**	
		Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
1990-12-31	
1991-12-31	
1992-12-31	
1993-12-31	
1994-12-31	
1995-12-31	
1996-12-31	
1997-12-31	
1998-12-31	
1999-12-31	

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
2000-12-31	
2001-12-31	
2002-12-31	
2003-12-31	
2004-12-31	
2005-12-31	
2005-12-31	
2006-12-31	
2007-12-31	
2008-12-31	
Current tax year 2009-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate.* of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED		614,556			
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	181,512			
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	796,068	=		
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–				
• prescribed expenditures not allowed by regulations	–		–		
• other deductions	–		–		
• non-arm's length transactions					
– expenditures for non-arm's length SR&ED contracts	–				
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–		
Subtotal	=	796,068 I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	796,068	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

Code 1101

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: Norfolk Power Distribution Inc.

Enter one of the following:

Business Number (BN): 86289 2593 RC0001

Social Insurance Number (SIN):

Tax year
From: 2010-01-01 (Year Month Day)
To: 2010-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 3

100 Contact person for the financial information: Rob Galipeau	**105** Telephone number/extension: (416) 360-7733	**110** Fax number: (416) 360-7733
115 Contact person for the technical information: Brad Randall	**120** Telephone number/extension: (519) 426-4574	**125** Fax number: (519) 426-4514

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	185,638
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	185,638
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	20,413
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	206,051
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	206,051

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		206,051
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	9,272
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	152,049
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	44,730
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	44,730
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	44,730
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	206,051	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	120,033		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	326,084	512 =	
Deduct				
• provincial government assistance	513 –	14,674	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	311,410	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	311,410
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	311,410

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	810	+	185,638
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	972
Subtotal (line 810 minus 812)	814	=	184,666

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Name of Specified Employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816)	816	+	
Salary base (total of lines 814 and 816)	818	=	184,666

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818 x 65%)	820	=	120,033

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. Development of a Self-Healing Smart-Grid Network	26,812		20,413
2. Development of Infrastructure to support Smart-Metering	125,829		
3. Document Imaging and Geographic Information System Dev	32,997		
Total	185,638		20,413

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) 605 185,638

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	
Technologists and technicians	634	3
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form ..... [X]
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 ..... [X]
3. completed Part 2 for each project ..... [X]
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures ..... [X]
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable ..... [ ]

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* ..... [X]
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable ..... [X]
3. retained documents to support the SR&ED expenditures you claimed ..... [X]
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 ..... [X]

* Form T1145, *Agreement ta Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement ta Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Brad Randall
Name of authorized signing officer of the corporation, or individual

Signature

170 2011-06-20
Date

175 BeneFACT Consulting Group Inc.
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number 1

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Development of a Self-Healing Smart-Grid Network

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-01 (Year Month)	2011-08 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility **228** 1 [X] Others, specify **229** Field Sites

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. **(Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge **(Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [X]	**236** 1 [X]
The improvement of existing	**237** 1 [ ]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

A smart electric grid that is capable of self healing employs innovative and intelligent monitoring, control and communication technologies to maintain and improve the reliability levels was the technological objective of this project. In order to improve the reliability of the grid, the supervisory control and data acquisition system (SCADA) needs to receive large amount of data in real time to determine whether a transformer station is off the grid and take measures to bypass power to that service area from another station. A first step into upgrading to that capability is to install a communications platform (in this case fiber cable) that allow for such large data volume to be transmitted reliably and rapidly over long distances. In our experience, the quantity of data we needed to transfer cannot reliably be achieved over long distances using other modes of communication such as wireless. As we could not use existing utility poles to carry the fiber cables, we had to bury the cable through an unused railway path, which had never been done before at Norfolk Power.

Specifically, we wanted to reduce the time it takes restore power to a service area when a transformer station experiences a failure as well as to obtain visual confirmation of the position of switches in a transformer station via live feed of video as a way to detect other possible causes of the shutdown. As a side benefit, fiber cables will allow us to improve monitoring, control

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

and security at our transformer stations by transmitting large volumes of data in video format to our control centers.

These advancements will pave the road for the full deployment of the required equipment and technology to achieve a fully functional smart electric grid.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The development of a smart grid has its fundamentals in installing the communications platform that will support the exchange of large quantities of data (e.g. video, voice and system information) in real time. We identified the following technological challenges:

When a transformer station goes off line, neighbouring stations may take the extra load. For this to happen in a timely manner large volumes of data need to be sent between SCADA control systems. We were uncertain how to increase the volume of data shared per unit time in a cost effective way.

Laying the fibre optic cable using existing utility poles is usually a cost efficient way; however, fees by a third party owner of the poles made it not viable. We were uncertain what other options were available in that locality.

We were unsure on how to bury the cable and ensure that it was safe from attack by water and animals. Also, burying the fibre optic cable underground was not possible along the entire route due to road crossings, deep drain systems and protected ecosystems. We were uncertain how to approach these in a cost effective way.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Among the different options available to transmit the data, fibre optic cable even though expensive in terms of installation costs, are reliable and offer great band width allowing us to send the large volumes of data per unit time we require.

Our original installation design consisted of using existing utility poles to carry the fibre cable. However, this design could not be implemented as we do not own all the utility poles in our service area and it was not cost effective to use the poles by another company or install additional poles.

We then decided to use buried cable for about 18 km. We modified the installation design to include areas where the fibre was carried on existing poles and areas where the fibre was buried. We used a walkway (previously a railway path) to bury our cable along most of the route and completed the connection using a short section on utility poles along a road. For the underground portion, we had to use a double armoured cable to ensure that it was not crushed by the weight of the ground as well as it was safe from attack by animals.

To install the cable through the railway path, we used a plough that would simultaneously place the cable about 1 m deep as it drove across the railway path. As we reached railway crossings, we had to splice the cable as the plough could not dig through the road. We utilized directional drilling to push the cable under the road and then connected the cables using heavy duty splice vaults to protect the installation.

Accessibility of equipment to the railway path was an issue as we had to consider environmental measures to assure that protected species of grass didn't get disturbed by the work through the field. To minimize the impact on the environment in the areas where the grass was growing, we decided to use a plough with a smaller footprint; however it increased the construction

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

timeline. Use of smaller ploughing equipment also meant that the depth of the buried cable had to be carefully monitored as the compacted dirt and gravel rail bed posed a challenge to this equipment.

Towards the end of the path, the rail lines were still in active use. This meant that we had to change the way we were putting the cable down. Instead of placing the cable from the top of the path, we now had to place it underneath the tracks at an angle. It was important that the cable was underneath the tracks so as it protect in during an accident such as derailment. After several iterations, we placed the cable 1 m deep at a 10 degree angle.

We encountered deep drain systems that could not be ploughed over and posed a challenge to directional drilling. We came up with a different approach and used a combination of buried and aerial techniques. We added a few poles to make an aerial crossing at these locations.

The aerial installation on utility poles had to be preceded by a load and resistance calculation by an external engineering firm; it showed that some poles had to be changed in order to support the additional load.

In order to make the connection inside the transformer stations the cables must be non dielectric to avoid any ground sources therefore preventing a ground return path through the cable. Also, we had to watch carefully for interference with the power cables as they may generate large arcs in case of a failure that could damage the fibre optic cable. The incorporation of fibre optic cable to our stations was a novel procedure for us.

To the end of fiscal year 2010 we had connected the fibre between two sub-stations; the next steps in fiscal year 2011 will include: Installation of a multiple load interrupter switches using the connection via fibre as opposed to the current communication via wireless. Fibre communication will allow us to initiate the remote control of switches and other important features towards the deployment of a smart grid network.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project	254 Name: Brad Randall	
255 1 [ ] Other employee of the company	256 Name:	
257 1 [X] External consultant	258 Name: Benefact Consulting	259 Firm: Benefact Consulting

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	261 Qualifications/experience and position title
1	Tim Roberts	Energy Services Manager; 20+ years industry experience
2	Peter Kramer	Lead Powerline Maintainer - 20+ years industry experience
3	Brad Randall	President and CEO; P. Eng; 25+ years industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	269 BN
1	1445078 Ontario Inc.	86373 2798 RC0001

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

- 270 1 [X] Project planning documents
- 271 1 [X] Records of resources allocated to the project, time sheets
- 272 1 [ ] Design of experiments
- 273 1 [X] Project records, laboratory notebooks
- 274 1 [ ] Design, system architecture and source code
- 275 1 [ ] Records of trial runs
- 276 1 [ ] Progress reports, minutes of project meetings
- 277 1 [ ] Test protocols, test data, analysis of test results, conclusions
- 278 1 [X] Photographs and videos
- 279 1 [ ] Samples, prototypes, scrap or other artefacts
- 280 1 [X] Contracts
- 281 1 [ ] Others, specify 282 ______

Part 2 - Project information (continued)

Project number **2**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Development of Infrastructure to support Smart-Metering

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-01 (Year Month)	2011-08 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project

210 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory

224 1 [ ] In a dedicated research facility

226 1 [X] In a commercial plant or facility

228 1 [X] Others, specify **229** Field Sites

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [X]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

The big picture is that we wanted to upgrade the Norfolk County utility billing system from a paper-trail based system, requiring staff to visit each site to inspect and record the meter values, to an electronic, automated smart-meter system, such as many other municipalities have been doing. We are a unique, independent power distribution company cooperating with other local distribution companies and our existing network infrastructure has been custom developed in the past to suit our county's particular blend of customers.

Thus, the primary advancement we were after was knowledge of how to integrate the new smart-meters and supporting devices and infrastructure with our existing infrastructure so that required information could be exchanged between and properly stored within the different interacting environments, and that mandatory notifications/alarms would be delivered to the right parties in a timely manner.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

A significant obstacle we had to overcome was learning how the smart-meters and a purchased proprietary system called Field Worker deliver and receive information (what information is accessible, and where it is located). The smart-meters send a file comprising upward of 50 distinct codes and strings of

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

information. Field Worker came preconfigured in a manner that was not fully compatible with our existing system. There were a myriad of software tools that came with it, but it wasn t clear which combination, if any at all, would enable us to complete the full exchange of information desired.

As well, Field Worker was not initially equipped to retrieve the additional information fields (VA, VAR's, kW) available on the Commercial and Industrial (CNI) meters that we wanted to populate in our system. We also ran into a problem of our system loading up both CNI meter accounts and residential accounts when the residential accounts residential accounts were not being called for. The reason for this happening was not clear to us.

We found we could not install smart-meters initially on new units (residential, commercial or industrial) our system would not recognize them. A short term solution was to first install conventional meters on these units and setup accounts by the old paper trail method, which takes approximately one month. Afterwards, we would send our personnel to replace the conventional meter with a smart meter, just as we would for existing units. This was inefficient and we wanted to find a way to bypass the middle step, but were not sure how.

Prior to upgrading to smart meters, a propagation study had determined the county ought only to require two relay towers and one additional device (an FRP) to provide adequate communication between smart-meters (on 18,000 residences) and our internal system. The hardware (propagation towers and devices) turned out to be inadequate and we were experiencing upward of 800 to 1000 stale meters (meters not communicating properly), when the number should have been less than 100. We did not know what additional infrastructure needed to be installed to resolve this problem.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

To aid in developing the required software for information traffic-flow management, we invested in a separate server such that our existing server could remain dedicated to managing information and bills processed in the conventional paper-trail manner in the meantime. We then installed a special software package and began experimenting with the multitude of software tools available in order to build programs to handle various required tasks. The software package came with a default configuration, but we quickly recognized this would not meet our needs. Developing our own custom programs took quite a bit of time as we had about 20 different tasks that could be running and our programs needed to be able to successfully handle each task with its unique information calls and distributions.

We validated these programs by creating a virtual network of environments (mimicking those to be present in the overall information network), generating test data, feeding this data into our traffic-flow programs, and observing which environment received data bits at the other end of the task. We made necessary tweaks as we noticed errors and scenarios that we had not anticipated. Because of the multitude of environments and the differences in file formats with which each one operates, we spent considerable time developing proper file conversion programs as well.

When we began installing the CNI meters, we noticed the additional fields that Field Worker was not capable of accessing and hence populating in our record system. We made a careful study of all the fields the CNI meters contain many of these were similar to the old, conventional meters they were replacing, but there were some new features as well that we examined and

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

thought strategically about whether or not their information would be useful for our records. Next, we contacted the designers of Field Worker and communicated to them the additional features we wanted to see. There were a handful of conversations to clarify points and to make sure the changes they were implementing would not conflict with our system. In the end, they supplied us an updated version that met our specifications.

With the CNI meters installed, we began finding that these meter accounts were being loaded up along with residential account information. As we examined the issue, we recognized a potential solution might be to reset certain codes programmed into the CNI meters so that they would be clearly distinct from residential meters. In conjunction with resetting these codes, we worked to develop an exception file to aid in the prevention of CNI meter information being loaded onto the system along with the residential accounts. This took some iterative work, both in the codes being reset and the exception file, but we eventually found a solution that worked.

Regarding the goal of getting our system to recognize smart meters on new residential units, we have not yet found a workable solution. A large part of the problem lies in how Field Worker was developed, so we spent considerable time communicating with the Field Worker designers, explaining how our server and record system works and assisting them in analyzing whether or not their proposed software developments will be compatible.

We spent a considerable amount reading the stale date meter reports provided to us by the meter suppliers (who also monitor the status of their products in the field) to identify geographical regions where meters were not communicating well, and the reasons communication had failed. Based on this lengthy investigation, we estimated the need for 7 additional FRP's to bring the network up to full functionality. We requested a new propagation study be conducted in an effort to gain official confirmation of the need for this additional infrastructure.

Summary:

- Developed information traffic flow management programs through analysis of various system file formats and simulations.

- Analyzed additional data fields available with CNI meters and made recommendations to Field Worker designers on how to improve their product.

- Articulated need for easier installation of smart-meters on new units to Field Worker designers and assisted them in establishing design requirements and assessing potential solutions.

- Analyzed stale meter reports to determine geographical regions in need, reasons for meter miscommunication, and recommended appropriate new infrastructure.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project — **254** Name: Brad Randall

255 1 [ ] Other employee of the company — **256** Name:

257 1 [X] External consultant — **258** Name: Benefact Consulting — **259** Firm: Benefact Consulting

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	261 Qualifications/experience and position title
1	Brad Randall	President and CEO; P. Eng; 25+ years industry experience
2	Kevin Witham	Technician; 10+ years industry experience
3	Wendy Lenders	Technician; 10+ years industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	269 BN
1		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents

271 1 [X] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [ ] Design, system architecture and source code

275 1 [ ] Records of trial runs

276 1 [X] Progress reports, minutes of project meetings

277 1 [ ] Test protocols, test data, analysis of test results, conclusions

278 1 [ ] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [X] Contracts

281 1 [ ] Others, specify **282**

Part 2 - Project information (continued)

Project number 3

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Document Imaging and Geographic Information System Developme

202 Project start date: 2010-01 (Year Month)

204 Completion or expected completion date: 2011-08 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.09 Software engineering and technology

Project claim history

208 1 [ ] Continuation of a previously claimed project

210 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory

226 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility

228 1 [X] Others, specify **229** Field Sites

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. **(Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge **(Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [X]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The technological objective of this project was to implement and enhance a
2. document imaging system, as well as a geographic information system (GIS).
3.
4. In this project, our goal was to implement the IBM Content Manager OnDemand
5. software, onto our AS400 platform. Through this implementation, we sought to
6. transition our document storage from the native spool file format of the
7. AS400, into a document imaging system, which would enable us to more easily
8. search through the files.
9.
10. Additionally, we endeavored to reduce the dependency of the end user on
11. outdated line maps. Therefore, we sought to transfer the mapped line data
12. from the AutoCAD software to the Esri ArcGIS software. Furthermore, we
13. aspired to integrate additional data from several databases into the new
14. ArcGIS software.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

1. Despite the claims of the IBM content management software to operate on
2. multiple platforms, the software would not import, analyze or index the
3. documents on our AS400 platform. This was increasingly challenging because
4. the AS400 platform was antiquated and provided little documentation for

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

interfacing with the new content management software.

We were further challenged to provide additional customizations and features to the document imaging system. This was challenging because the AS400 platform did not provide the same level of support as modern day systems, and each client required different customizations.

When we attempted to transfer the mapping information from the AutoCAD to the ArcGIS software, we discovered that the parameters of each data type were different between the two softwares. This caused inaccuracies in the data once it had been imported into the ArcGIS software. Therefore, we were challenged to correct these inaccuracies.

We were also challenged by inaccuracies in the ArcGIS mappings, due to the variances in the data between the multiple databases and spreadsheets.

We encountered additional challenges with the accuracy of the mapped data because the AutoCAD maps were outdated and did not accurately reflect the foot print of today's buildings.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Our original AS400 platform stored documents in a spool file. We sought to implement the Content Manager OnDemand software, in order to provide the capability to scan documents and assign index tags that would facilitate easy retrieval. Unfortunately, our attempts to implement the new software were unsuccessful. Through extensive investigation of the content management software, we discovered several errors in the software that made it incompatible with our system. We attempted to perform several modifications to the software in order to account for these incompatibilities. While these solutions provided a measure of success, our modifications could not be maintained, and were not flexible to change. We therefore transitioned to an alternate vendor. However, this new software still did not operate smoothly on our system. In order to overcome this obstacle, we analyzed the source documents of the AS400 platform, and identified configuration adjustments that would enable the two systems to function together effectively.

We were next challenged to extend the functionality of the document imaging system. We accomplished this challenge by developing a module to integrate with our customer billing system. Through this module, a keyboard command launches a call to our document imaging software and loads the documents into the billing system.

In order to update our distribution maps to utilize current technology, we sought to transfer the data from our old AutoCAD maps to the new ArcGIS software. While both programs included the functionality to import and export data, we discovered that the way in which the data was defined in AutoCAD was different than the data definitions in ArcGIS. This caused the information to be transferred incorrectly, and resulted in inaccuracies on the new maps. We attempted to develop an automated solution to this obstacle, by creating a module to import a trench layer from the AutoCAD system, and performing a comparison between the AutoCAD layer and the corrupted layer in ArcGIS. Unfortunately, we were unable to design an automated program with sufficient visual recognition capabilities to accurately compare the two layers. Therefore, we employed a manual process to review each area of the map, and move the data points on the ArcGIS maps by the delta between its position and the position of the data point on the AutoCAD map.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

We encountered additional challenges when we attempted to import data from multiple spreadsheets and databases into the ArcGIS software. Since the attributes of the data assets could be managed automatically, we attempted to develop a process to automatically link the data from these sources into the ArcGIS software. Unfortunately, discrepancies between the data sources yielded additional inaccuracies in the final map. Therefore, we combined the tertiary data sources into a single Excel spreadsheet, and manually verified the accuracy of the aggregate data, prior to importing it into ArcGIS.

The AutoCAD maps were renditions of fifty year old hand-drawn maps whereas the ArcGIS maps were only four years old. Since the building footprints had changed significantly in that time period, we were challenged to match the line data points between the two maps. Therefore, we developed a set of rules to dictate the location of the data points, with respect to the footprints of today's buildings on the up-to-date map.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year,** how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project — **254** Name: Brad Randall

255 1 [ ] Other employee of the company — **256** Name:

257 1 [X] External consultant — **258** Name: Benefact Consulting — **259** Firm: Benefact Consulting

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	261 Qualifications/experience and position title
1	Cordilia Rustenburg	Engineering Manager; 19+ years industry experience
2	Brad Randall	President and CEO; P. Eng; 25+ years industry experience
3	Karen Tomajko	Engineering Draftsperson; 10+ years industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	269 BN
1		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1 [X] Project planning documents	276	1 [X] Progress reports, minutes of project meetings
271	1 [X] Records of resources allocated to the project, time sheets	277	1 [ ] Test protocols, test data, analysis of test results, conclusions
272	1 [ ] Design of experiments	278	1 [ ] Photographs and videos
273	1 [X] Project records, laboratory notebooks	279	1 [ ] Samples, prototypes, scrap or other artefacts
274	1 [ ] Design, system architecture and source code	280	1 [X] Contracts
275	1 [ ] Records of trial runs	281	1 [ ] Others, specify 282

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and did not expire before 2008 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 **(consolidated)**, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 ______ x 10 % = 240

Credit allocated from a partnership 250

Subtotal

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures

Current expenditures (from line 557 on Form T661)		311,410		
Add:				
Contributions to agricultural organizations for SR&ED under paragraph 37(1)(a)*				
Deduct:				
Government and non-government assistance*				
Contributions to agricultural organizations for SR&ED*		▶		
Current expenditures (including contributions to agricultural organizations for SR&ED)*		311,410 ▶	350	311,410
Capital expenditures (from line 558 on Form T661)			360	
Repayments made in the year (from line 560 on Form T661)			370	
Total (this must equal the amount from line 570 on Form T661)*			380	311,410

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? **385** 1 Yes [X] 2 No [ ]

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). **390** ______

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return). **395** ______

c) Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. **398** ______

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1: Tax year ends before February 26, 2008.
[($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)] . . . . ________

Calculation 2: Tax year starts after February 26, 2008 and ends before January 1, 2010.
[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 3: Tax year includes February 26, 2008.
AA + [(BB **minus** AA) x (CC **divided by** DD)] where,
- **AA** = [($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)];
- **BB** = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **CC** = number of days in the tax year after February 25, 2008;
- **DD** = number of days in the tax year. . . . . ________

Calculation 4: Tax year starts after December 31, 2009.
[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 5: Tax year includes January 1, 2010.
EE + [(FF **minus** EE) x (GG **divided by** HH)] where,
- **EE** = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **FF** = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **GG** = number of days in the tax year after December 31, 2009;
- **HH** = number of days in the tax year. . . . . ________

Enter the amount from Calculation 1, 2, 3, 4 or 5, whichever is applicable ________ *G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ________ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ________ x ________ Number of days in the tax year ________ / 365 = ... ________ I

365

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ________

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	311,410	x	20 %	=	62,282	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=		N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=		
480		x	20 %	=		
			Total			O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 62,282

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired*	515			
Subtotal				
ITC at the beginning of the tax year			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540	62,282		
Credit allocated from a partnership	550			
Subtotal		62,282		62,282
Total credit available				62,282
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	62,282		
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
Subtotal		62,282		62,282
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED			620	

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12) . . . . . ______ R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) ______ S

Refundable credits (amount R or S, whichever is less)* . . . . . ______ T

Amount J from Part 11 . . . . . ______ U

Subtract: Amount T or U, whichever is less . . . . . ______ V

Net amount (if negative, enter "0") . . . . . ______ W

Amount W ______ x 40 % . . . . . ______ X

Add: Amount V . . . . . ______ Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ______ Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . ______ AA

Amount J from Part 11 . . . . . ______ BB

Subtract: Amount AA or BB, whichever is less . . . . . ______ CC

Net amount (if negative, enter "0") . . . . . ______ DD

Amount M from Part 11 . . . . . ______ EE

Amount DD or EE, whichever is less ______ x 40 % . . . . . ______ FF

Add : Amount CC above . . . . . ______ GG

Refund of ITC (amounts FF **plus** GG) . . . . . ______ HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ________ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) _______________ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 _______________ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826 ▶			VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired* 845

Subtotal ▶

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18 870 x 10 % = 880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures 890

* The credit is eligible for a 20 year carryforward effective for credits earned in 2003 and later tax years.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) .... **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1.					
				Total current-year credit (enter at line 640)	

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year ....

Deduct:

Credit deemed as a remittance of co-op corporations **612**

Credit expired after 20 tax years **615**

Subtotal ▶

ITC at the beginning of the tax year **625**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **630**

ITC from repayment of assistance **635**

Total current-year credit (total of column 605) **640**

Credit allocated from a partnership **655**

Subtotal ▶

Total credit available ....

Deduct:

Credit deducted from Part I tax (enter on line B4 in Part 30) **660**

Credit carried back to the previous year(s) (from Part 23) .... DDD

Subtotal ▶

ITC closing balance from apprenticeship job creation expenditures **690**

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day			
1st previous tax year				Credit to be applied	**931**	
2nd previous tax year				Credit to be applied	**932**	
3rd previous tax year				Credit to be applied	**933**	
				Total (enter on line DDD in Part 22)		

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year **715** ________ EEE

Add: Specified child care start-up expenditures from the current tax year .... **705** ________ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) .... ________ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG .... **725** ________ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") ________ III

Add: Repayments of government and non-government assistance .... **735** ________ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) .... **745** ________

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745) .... ______ x 25 % = ______ KKK

Number of child care spaces .... 755 ______ x $ 10,000 = ______ LLL

ITC from child care spaces expenditures (amount KKK or LLL, whichever is less) .... ______ MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year .... ______

Deduct:

Credit deemed as a remittance of co-op corporations .... 765 ______

Credit expired after 20 tax years .... 770 ______

Subtotal ______ ▶ ______

ITC at the beginning of the tax year .... 775 ______

Add:

Credit transferred on amalgamation or wind-up of subsidiary .... 777 ______

Total current-year credit (amount MMM above) .... 780 ______

Credit allocated from a partnership .... 782 ______

Subtotal ______ ▶ ______

Total credit available .... ______

Deduct:

Credit deducted from Part I tax (enter on line B5 in Part 30) .... 785 ______

Credit carried back to the previous year(s) (from Part 27) .... ______ NNN

Subtotal ______ ▶ ______

ITC closing balance from child care spaces expenditures .... 790 ______

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2009-12-31	Credit to be applied	941	______
2nd previous tax year	2008-12-31	Credit to be applied	942	______
3rd previous tax year	2007-12-31	Credit to be applied	943	______
		Total (enter on line NNN in Part 26)		______

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) .... **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC .. **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property .... **797** ______

Amount from line 795 or line 797, whichever is less .... ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. .... ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	62,282	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)		B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	62,282	B6

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

AMENDED

Amount calculated on line 9999 from Schedule 125				1,999,889 A
Add:				
Provision for income taxes – current		101	531,000	
Amortization of tangible assets		104	2,702,963	
Loss on disposal of assets		111	3,138	
Scientific research expenditures deducted per financial statements		118	206,051	
Reserves from financial statements – balance at the end of the year		126	1,820,375	
Subtotal of additions			5,263,527 ▶	5,263,527
Other additions:				
Miscellaneous other additions:				
603				
OITC/ORDTC/BCRDTC/ABRDTC from prior year - 12(1)(x)	8,168			
Total	8,168	293	8,168	
604				
Total		294		
Subtotal of other additions		199	8,168 ▶	8,168
Total additions		500	5,271,695 ▶	5,271,695
Deduct:				
Capital cost allowance from Schedule 8		403	3,409,012	
Cumulative eligible capital deduction from Schedule 10		405	15,508	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	44,730	
Reserves from financial statements – balance at the beginning of the year		414	1,874,160	
Subtotal of deductions			5,343,410 ▶	5,343,410
Other deductions:				
Miscellaneous other deductions:				
704				
Total		394		
Subtotal of other deductions		499	0 ▶	0
Total deductions		510	5,343,410 ▶	5,343,410
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,928,174

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

AMENDED

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ________________ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,928,174		1,928,174	210,525

	Line	Amount		Amount	
Ontario basic income tax (from Schedule 500)	270	250,504			
Deduct: Ontario small business deduction (from schedule 500)	402	39,979			
Subtotal (if negative, enter "0")		210,525	▶	210,525	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272	30,099			
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal		30,099	▶	30,099	B6
Subtotal (amount A6 **plus** amount B6)				240,624	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				240,624	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416	14,674	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				225,950	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				225,950	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	29,006			
Subtotal		29,006	▶	29,006	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				254,956	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454	10,000			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		10,000	▶	10,000	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	244,956	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	244,956

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Norfolk Power Distribution Inc.	86289 2593 RC0001	2010-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return*.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	326,084	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		326,084	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		326,084	►	326,084	E
Deduct: Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			326,084	G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)			326,084	x	4.50 %	= 200	14,674	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *						205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment			210	x	4.50 %	= 215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =		x	4.50 %	= 225		K
Current part of the ORDTC (total of amounts H to K)						230	14,674	L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year					M	
Deduct: ORDTC expired after 20 tax years	300				N	
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305				O	
Add:						
ORDTC transferred on amalgamation or windup	310				P	
Current part of ORDTC (amount L in Part 2)		14,674	Q			

Are you waiving all or part of the current part of the ORDTC? **315** Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320		R				
Subtotal (amount Q **minus** amount R)		14,674	►	14,674	S		
ORDTC available for deduction (total of amounts O, P and S)				14,674	►	14,674	T
Deduct:							
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)				14,674	U		
ORDTC carried back to a previous tax year (from Part 4)					V		
Subtotal (amount U **plus** amount V)				14,674	►	14,674	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)	325						X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2009-12-31	Credit to be applied	901	
2nd previous tax year	2008-12-31	Credit to be applied	902	
3rd previous tax year	2007-12-31	Credit to be applied	903	
		Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
1991-12-31	
1992-12-31	
1993-12-31	
1994-12-31	
1995-12-31	
1996-12-31	
1997-12-31	
1998-12-31	
1999-12-31	
2000-12-31	

	Tax year of origin (earliest tax year first) Year Month Day	Credit available
	2001-12-31	
	2002-12-31	
	2003-12-31	
	2004-12-31	
	2005-12-31	
	2005-12-31	
	2006-12-31	
	2007-12-31	
	2008-12-31	
	2009-12-31	
Current tax year	2010-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate* of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC	DD	EE
	The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF	GG	HH
	Amount determined by the formula (CC x DD) – EE (using the columns above)	The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ________ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ________ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ________ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ________ LL

Amount KK **plus** amount LL . . . . ________ x 23.56 % = ________ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ________ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ________ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

	Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED	206,051			
Add				
• payment of prior years' unpaid expenses (other than salary or wages)	+			
• prescribed proxy amount (Enter "0" if you use the traditional method)	+ 120,033			
• expenditures on shared-use equipment			+	
• other additions	+		+	
Subtotal	= 326,084		=	
Less				
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	−			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	−			
• prescribed expenditures not allowed by regulations	−		−	
• other deductions	−		−	
• non-arm's length transactions				
− expenditures for non-arm's length SR&ED contracts	−			
− purchases (limited to costs) of goods and services from non-arm's length suppliers	−		−	
Subtotal	= 326,084	I	=	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			= 326,084	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency   Agence du revenu du Canada

Business Consent form

Complete this form to consent to the release of confidential information about your program account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre (see Instructions).** Make sure you complete this form correctly, since we cannot change the information that you provided. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount.**

Note: Read all the instructions before completing this form.

Part 1 – Business information

Complete this part to identify your business (all fields have to be completed)

Business name: Norfolk Power Distribution Inc.

BN: 862892593   Telephone number: (519) 426-4440

Part 2 – Authorize a representative – Complete either part a) or b)

a) Authorize access by telephone, fax, mail or in person by appointment

If you are giving consent for an individual, enter that person's full name. If you are giving consent to a firm, enter the name and BN of the firm. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the firm's name and BN. If you do not identify an individual of the firm, then you are giving us consent to deal with anyone from that firm.

Note: If you are authorizing a representative (individual or firm) who is not registered with the Represent a client service, the phone number is required.

Name of Individual: ______

Name of Firm: ______

Telephone number: ______   Extension: ______   **BN:** ______

OR

b) Authorize online access (includes access by telephone, fax, mail or by appointment)

You can authorize your representative to deal with us through our online service for representatives. The Business Number must be registered with the "Represent a Client" service to be an online representative. **Our online service does not have a year-specific option, so your representative will have access to all years.** Please enter the name and RepID of the individual **or** GroupID and name of the group **or** name and BN of the firm.

Name of individual: ______ **and** **RepID:** ______

OR

Name of group: ______ **and** **GroupID:** G

OR

Name of firm: BeneFACT Consulting Group Inc. **and** **BN:** 807658745

Telephone number: (416) 360-7733   Extension: ______

Part 3 – Select the program accounts, years and authorization level

a) Program Accounts – Select the program accounts the above individual or firm is authorized to access (tick only box A or B).

A. [X] This authorization applies to all program accounts and all years.

Expiry date: ______

AND

Authorization level (tick level 1 or 2)

[X] Level 1 lets CRA disclose information only on your program account(s); **or**

[ ] Level 2 lets CRA disclose information **and** accept changes to your program account(s).

OR

B. [ ] This authorization applies only to program accounts and periods listed in Part 3b). If you ticked this option, you must complete 3b).

Business Consent form (RC59 continued)

Part 3 – Select the program accounts, years and authorization level (continued)

b) Details of program accounts and fiscal periods – Complete this area only if you ticked box B in Part 3a) on page 1.

If you ticked box B in part 3a), you have to provide at least one program identifier. You can then tick the "All program accounts" box for that program identifier **or** enter a reference number. Provide the authorization level (tick **either** box 1 to disclose information or box 2 to disclose information **and** accept changes to your program account).

You can also tick the "All years" box to allow unlimited tax year access **or** enter a specific fiscal period (specific period authorization **is not available** for online access). You can also enter an expiry date to automatically cancel authorization. If more authorizations or more than four program identifiers are needed, complete another Form RC59.

Program identifier	All program accounts		Reference number	Authorization level 1	Authorization level 2	All years	or	Specific fiscal period (not available for online access) Year-end	Expiry date
	☐	or		☐	☐	☐	or		
	☐	or		☐	☐	☐	or		
	☐	or		☐	☐	☐	or		
	☐	or		☐	☐	☐	or		

Part 4 – Cancel one or more authorizations

Complete this part **only** to cancel authorization(s)

☐ **A.** Cancel **all** authorizations.

☐ **B.** Cancel authorization for the individual, group, or firm identified below.

☐ **C.** Cancel authorization for specific program account(s) ______________.

Name of Individual: ______________ and **RepID:** ______

OR

Name of Group: ______________ and **GroupID:** G

OR

Name of Firm: ______________ and **BN:** ______

Part 5 – Certification

This form has to be signed by an authorized person of the business such as an owner, a partner of a partnership, a director of a corporation, an officer of a non-profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual, group, or firm listed in Part 2 of this form or cancel the authorizations listed in Part 4.

First name: Brad

Last name: Randall

Sign here ▶ ______________

Date 2011-05-24

We wil not process this form unless it is **signed** and **dated** by an authorized person of the business.

The *Privacy Act* protects information given on this form, which is kept in personal information bank numbers CRA PPU-175 and 223.

APPENDIX 9 – BOARD STAFF INTERROGATORIES

Charge Type 146

BS IR#69)

2010 GLOBAL ADJUSTMENT ANALYSIS

2010 GLOBAL ADJUSTMENT ANALYSIS	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Global Adjustment Expense (from IESO Invoice)	966,254.95	826,664.27	1,245,045.08	969,552.75	727,426.92	788,930.65	283,576.50	470,379.36	911,060.75	1,243,349.16	1,067,481.09	1,096,157.46
Total System Load (UTILISMART printout)	35,757,337.10	31,890,292.70	31,870,318.40	27,540,533.30	29,878,942.20	31,983,882.20	37,368,167.90	37,935,846.40	31,676,340.10	30,465,251.00	30,898,961.30	33,526,826.40
RPP customer system load (from Cheryl's annual summary)	18,115,457.66	17,817,347.95	16,144,924.16	15,534,459.68	12,969,189.68	13,915,698.93	15,633,190.43	19,984,373.85	16,667,754.64	14,052,505.05	14,467,717.93	15,237,563.55
Non-RPP Global Adjutment	476,728.83	364,800.68	614,327.87	422,668.71	411,681.55	445,678.97	164,940.62	222,586.37	431,670.23	669,837.71	567,657.97	597,966.29
Billed Global Adjustment (from Customer Revenue) (note revenue is entered as a positive, negative value = expense to LDC (DR in GL)) ~ Includes LTLT Revenue accrual as appropriate												
LDC Total	$588,971.47	504,280.47	495,410.25	470,427.56	629,308.11	493,030.24	363,606.56	372,773.67	156,360.68	303,533.57	463,150.80	656,148.48
Total GA Revenue	**588,971.47**	**504,280.47**	**495,410.25**	**470,427.56**	**629,308.11**	**493,030.24**	**363,606.56**	**372,773.67**	**156,360.68**	**303,533.57**	**463,150.80**	**656,148.48**
Monthly Variance	(112,242.64)	(139,479.79)	118,917.62	(47,758.85)	(217,626.56)	(47,351.27)	(198,665.94)	(150,187.30)	275,309.55	366,304.14	104,507.17	(58,182.19)
Cummulative Variance	1,398,742.22	1,259,262.44	1,378,180.06	1,330,421.21	349,427.94	302,076.67	103,410.73	(46,776.57)	228,532.98	594,837.12	699,344.29	641,162.09
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.89%	0.89%	0.89%	1.20%	1.20%	1.20%
Monthly Interest	692.53	641.090186	577.16	631.67	609.78	160.15	224.04	76.70	(34.69)	228.53	594.84	699.34
Cummulative Interest	77,011.80	77,652.89	78,230.05	78,861.72	4,491.49	4,651.65	4,875.69	4,952.38	4,917.69	5,146.22	5,741.06	6,440.40

G.A. Principal Amount Approved for Recovery in 2010 Rates $ 763,366.70
G.A. Interest Amount Approved for Recovery in 2010 Rates $ 74,980.00

2010 Variance Account 1588

Jan-10	2,264,506.44	1,631,463.03		633,043.41	1,137,147.05	231.05		-120,385.68	0.55%
Feb-10	1,973,853.73	2,217,980.41		-244,126.68	893,020.37	521.19		-119,864.49	
Mar-10	2,150,009.48	1,972,413.76		177,595.72	1,070,616.09	409.30		-119,455.19	
Apr-10	1,703,605.19	1,530,033.69		173,571.50	1,244,187.58	490.70		-118,964.49	0.55%
May-10	1,917,597.27	1,952,944.11	-215,955.36	-251,302.20	992,885.38	570.25	122,786.48	4,392.24	
Jun-10	2,166,216.14	2,202,995.11		-36,778.97	956,106.40	455.07		4,847.32	
Jul-10	2,397,567.47	2,549,296.80		-151,729.33	804,377.08	709.11		5,556.43	0.89%
Aug-10	2,631,948.29	3,274,066.98		-642,118.69	162,258.39	596.58		6,153.01	
Sep-10	2,160,728.94	1,899,189.87		261,539.07	423,797.45	120.34		6,273.35	
Oct-10	2,294,213.99	1,559,999.37		734,214.62	1,158,012.08	423.80		6,697.15	1.20%
Nov-10	2,031,653.01	1,769,732.17		261,920.84	1,419,932.92	1,158.01		7,855.16	
Dec-10	2,442,812.35	3,024,384.25		-581,571.90	838,361.02	1,419.93		9,275.09	
	26,134,712.30	25,584,499.56		334,257.38		7,105.34	122,786.48		
G/L Balance	26,134,712.30	25,584,499.56		550,212.74					
Difference	-	-			(838,361.02)			(9,275.09)	

APPENDIX 10 – BOARD STAFF INTERROGATORIES

Contractor Invoices April 28, 2011 Wind Storm

BS IR#70b)

K-LINE MAINTENANCE & CONSTRUCTION LIMITED
12731 Highway 48, Stouffville, Ontario, Canada L4A 7X5
Tel: (905) 640-2002 - Fax (905) 640-8887 - www.K-Line.ca

INVOICE NO
101055

05.24

Date: April 30, 2011

CUSTOMER 12001

Norfolk Power Distribution Inc.
70 Victoria Street
Simcoe, ON N3Y 4N6

CUSTOMER REFERENCES

P.O. No.: 5100 100
Contact: Paul McCready
Terms: Net 30 Days
2% per month charged on overdue accounts

PROJECT DESCRIPTION

Norfolk-Emergency Storm Damage
Storm Damage Repairs
Port Dover & Simcoe

PROJECT REFERENCES

Project No.: 11449-11-10
Project Manager.: J. Wood
Last Day Worked.: Apr 2011

DESCRIPTION OF CHARGES

DESCRIPTION	RATE CODE	QTY	RATE	EXTENSION
Emergency Call - Storm Damage Repairs				
April 28 - May 1, 2011				
Labour - Premium Time				
3 x Foreman	hrs @	96.50	209.00	20,168.50
3 x Journeyman Lineman	hrs @	123.50	193.50	23,897.25
1 x Apprentice - 4th Year	hrs @	50.50	169.50	8,559.75
1 x Apprentice - 3rd Year	hrs @	50.50	157.00	7,928.50
2 x Apprentice - 1st Year	hrs @	45.00	135.50	6,097.50
Living Allowance (Total Man Hours)	hrs @	366.00	10.00	3,660.00
Equipment				
Pick Up Truck	hrs @	116.00	20.00	2,320.00
Double Bucket Truck 65'+	hrs @	89.00	88.00	7,832.00
Double Bucket Truck 55'	hrs @	21.00	79.00	1,659.00
RBD	hrs @	71.50	58.00	4,147.00
Combo Trailer	hrs @	21.00	17.00	357.00

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	86 626.50
1111	11 261.46

WO # 5100100.

APPROVED BY: Date: May 16/11

DATE: Sign:

W.O. ~~Revenue Canada~~ Busines No.10285 9246 RT0001:

SUBTOTAL	86,626.50
GST	
PST	
HST	11,261.46
AMOUNT DUE	$97,887.96

SUPER SUCKER HYDRO VAC SERVICE INC.

INVOICE

623 Shaver Road
ANCASTER, ONTARIO L9G 3K9
(905) 304-9513 Fax (905) 648-4281

NO 11930

DATE 30/04/2011

PAGE 1

SOLD TO
Norfolk Power
P. O. Box 588
70 Victoria St.
Simcoe, Ontario N3Y 4N6

SHIP TO
Norfolk Power

ITEM NO.	QUANTITY	UNIT	DESCRIPTION	GST PST	UNIT PRICE	AMOUNT
h-vac	7.5	hours	Hydro-Vac Excavation (Ticket #11958)	H	230.00	1,725.00
dump	1.0	dump	Dumping Fee	H	85.00	85.00
h-vac	17.5	hours	Hydro-Vac Excavation (Ticket #11957)	H	230.00	4,025.00
dump	2.0	dumps	Dumping Fee	H	85.00	170.00
h-vac	7.5	hours	Hydro-Vac Excavation (Ticket #11960)	H	230.00	1,725.00
dump	1.0	dump	Dumping Fee	H	85.00	85.00
			H - HST 13%			
			HST			1,015.95

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	7815.00
11111	1015.95

APPROVED BY: MBoh.

DATE: May 10/11

W.O. #: 5100100.

Terms: Net 30. Due 30/05/2011.

Super Sucker Hydro Vac Service Inc. HST: #896617511RC0001

COMMENTS

TOTAL 8,830.95

SUPER SUCKER HYDRO VAC SERVICE INC.

RECEIVED May 13/11

05-24

INVOICE

623 Shaver Road
ANCASTER, ONTARIO L9G 3K9
(905) 304-9513 Fax (905) 648-4281

NO 11983

DATE 01/05/2011

PAGE 1

SOLD TO

Norfolk Power

P. O. Box 588
70 Victoria St.
Simcoe, Ontario N3Y 4N6

SHIP TO

Norfolk Power

ITEM NO.	QUANTITY	UNIT	DESCRIPTION	GST PST	UNIT PRICE	AMOUNT
> h-vac	4	hours	Hydro-Vac Excavation (Ticket #11434)	H	230.00	920.00
			H - HST 13%			
			HST			119.60

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	920.00
11111	119.60

APPROVED BY: [signature]

DATE: May 13/11

W.O. # 5100100.

>

Terms: Net 30. Due 31/05/2011.

Super Sucker Hydro Vac Service Inc. HST: #896617511RC0001

COMMENTS

TOTAL 1,039.60

To Reorder Call PROFORMA MSK GRAPHICS at 905-387-9744 M365510243

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904607909	April 30, 2011	May 23, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER				
PO BOX 588 70 VICTORIA STREET, SIMCOE, ON				
Maintenance	04/30/2011	1,974.00		1,974.00
(PO #4671)				
-				
DEMAND - Storm Work - Various Addresses				
-				
April 30, 2011 - 10.5 hours overtime				
-				
Total of applied HST (105207252RT0001) taxes:			256.62	256.62
Total of current services		**1,974.00**	**256.62**	**2,230.62**

...ED BY: [signature]

May 16/2011

5100100

WORK ORDER NO G.L. ACCOUNT	AMOUNT
5100100	1974.00
11111	256.62

Davey info just for you

DAVEY.COM

If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY

For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904607911	April 30, 2011	May 23, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER **PO BOX 588 70 VICTORIA STREET, SIMCOE, ON**				
Maintenance *(PO #4671)* - DEMAND - Storm work - April 28, 2011 - 2 hours regular - 6 hours overtime -	04/28/2011	1,414.00		1,414.00
Total of applied HST (105207252RT0001) taxes:			183.82	183.82
Total of current services		**1,414.00**	**183.82**	**1,597.82**

APPROVED BY:

DATE: May 16/2011

W.O. #: 5100100

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	1414.00
11111	183.82

Davey info just for you

DAVEY.COM
If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY
For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904608755	April 30, 2011	May 23, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER				
PO BOX 588 70 VICTORIA STREET, SIMCOE, ON				
Maintenance	04/28/2011	376.00		376.00
(PO #4671)				
DEMAND - STORM WORK				
April 28, 2011 - 2 hours overtime				
Total of applied HST (105207252RT0001) taxes:			48.88	48.88
Total of current services		**376.00**	**48.88**	**424.88**

...ED BY:

May/16/2011

5100100

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	376.00
1111	48.88

DAVEY.COM

Davey info just for you

If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY

For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904608757	May 06, 2011	May 23, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER				
PO BOX 588 70 VICTORIA STREET, SIMCOE, ON				
Maintenance	04/30/2011	12,280.00		12,280.00
(PO #4671) (Contract #43186799)				

-
DEMAND
-
April 25, 2011 - Maple Court, Port Ryerse - 6 hours
April 27, 2011 - Norfolk County - 8 hours
April 28, 2011 - Storm Work - 8 hours regular, 7 hours overtime
April 29, 2011 - Storm Work - 8 hours regular, 7 hours overtime
April 30, 2011 - Storm Work - 28.5 hours overtime - 2 crews
-

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5135102	2002.00
5100100	10278.00
1111	1596.40

Total of applied HST (105207252RT0001) taxes:		1,596.40	1,596.40
Total of current services	**12,280.00**	**1,596.40**	**13,876.40**

5135102 → 2,002.00 APPROVED BY: [signature]

5100100 → 10,278.00 DATE: May 10/2011

W.O. #

DAVEY.COM
Davey info just for you
If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY
For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

05-24

DARLINGTON WIRING & PLUMBING LTD.

1425 Norfolk County Rd. 21,
R. R. 1,
Delhi, ON N4B 2W4
Ph: 519-875-2571 Fax: 519-875-2512

Date	Invoice #
03/05/2011	11-9584

Invoice To
Norfolk Power* Attention Mark Booker, Box 588, 70 Victoria St., Simcoe, ON N3Y 4N6

P.O. No.	Terms
5100100	Due on receipt/2% aft...

Qty	Item	Description	U/M	Rate	Amount
	WIRING	Labour		1,154.25	1,154.25
1		ESA inspection fees - 11 Arthur St., Simcoe		196.00	196.00
		Connecting generator at 11 Arthur St., Simcoe. Return to reconnect hydro service, reverse phasing on elevator & test.			
		HST (ON) on sales		13.00%	175.53
					$175.53

APPROVED BY: MBdr
DATE: May 17/4
W.O. #: 5100100

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	1350.25
11111	175.53

Total	$1,525.78
Payments/Credits	$0.00
Balance Due	$1,525.78

Thank you for your business.

2% Interest Monthly after 15 Days

GST/HST No. 101270908

ARK Consutling
39 McColl Place
Caledonia, ON
N3W 1k4
BN: 83914 5869

Invoice

DATE	INVOICE #
01/05/2011	204

BILL TO
Norfolk Power Distribution Inc. P.O. Box 588 70 Victoria Street Simcoe, ON N3Y 4N6

DUE DATE	P.O. NUMBER
16/05/2011	

DATE	DESCRIPTION	HOURS	RATE	AMOUNT	HST
2011 04 04	Control Room Support	8	65.00	520.00	67.60
2011 04 06	Control Room Support	8	65.00	520.00	67.60
2011 04 07	Control Room Support	8	65.00	520.00	67.60
2011 04 08	Control Room Support	8	65.00	520.00	67.60
2011 04 12	Control Room Support	8	65.00	520.00	67.60
2011 04 13	Control Room Support	8	65.00	520.00	67.60
2011 04 14	Control Room Support	8	65.00	520.00	67.60
2011 04 18	Control Room Support	8	65.00	520.00	67.60
2011 04 19	Control Room Support	8	65.00	520.00	67.60
2011 04 20	Control Room Support	8	65.00	520.00	67.60
2011 04 21	Control Room Support	8	65.00	520.00	67.60
2011 04 26	Control Room Support	8	65.00	520.00	67.60
2011 04 27	Control Room Support	8	65.00	520.00	67.60
2011 04 28	Control Room Support	8	65.00	520.00	67.60
2011 04 29	Control Room Support	8	65.00	520.00	67.60
2011 04 28 Storm	Storm Restoration	9	130.00	1,170.00	152.10
2011 04 29 Storm	Storm Restoration	2	130.00	260.00	33.80
2011 04 30 Storm	Storm Restoration	11	130.00	1,430.00	185.90

	AMOUNT	
5100100	3900	00
5010100	6700	00
1111	1385	80

Please remit to above address.

PW
May 4/11
5100100 – 3,900
5010100 – 6,700

Subtotal	10,660.00
HST (Reg. No. GST 83914 5869 RT0001)	1,385.80
Total($):	12,045.80

Wayne Brett

INVOICE

13 Calvert Drive
Port Dover, ON N0A 1N4

Date: 29-Apr-11
Invoice #: 26

Bill To:
Norfolk Power Distribution Inc.
P. O. Box 588
70 Victoria Street
Simcoe, ON N3Y 4N6

Description	Hours	Rate	Amount
April 25, 2011	7.75	$ 55.00	$ 426.25
April 26, 2011	8.00	$ 55.00	$ 440.00
April 27, 2011	8.50	$ 55.00	$ 467.50
April 28, 2011	8.00	$ 55.00	$ 440.00
April 29, 2011	9.75	$ 55.00	$ 536.25
Professional Services for week.			
		Sub-total	$ 2,310.00
HST #845866201RT0001		HST	$ 300.30
		Total	$ 2,610.30

Please make cheque payable to Wayne Brett.

NEI Chargeable time for the week 3 Hrs $ 165.00

APPROVED BY:

NPDI Chargeable time for the week 39 Hrs - 13.75 = 25.25 $ 2,145.00

DATE:

W.O. #:

Storm w/o 5100100 Thurs. Friday 479.75 = 13.75

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5615100	1388.75
1103002	165.00
5100100	756.25
11111	300.30

RECEIVED June 8/11

Tillsonburg
a place to build your future

Invoice

INVOICE NO: S11 - 56
DATE: JUNE 1, 2011

TOWN OF TILLSONBURG

CUSTOMER SERVICE CENTRE

10 Lisgar Avenue
Tillsonburg, Ontario N4G 5A5
Phone (519)842-9200 Fax (519)688-0759

TO: NORFOLK POWER
70 VICTORIA ST
SIMCOE, ONTARIO
N3Y 4N6

S.O. NUMBER	Date:	Terms
N/A	1-Jun-11	net 30 days

QUANTITY	DESCRIPTION	RATE	AMOUNT
	STORM DAMAGE ASSISTANCE - APRIL 29 - MAY 1, 2011		
67	LABOUR CHARGE	43.10	$2,887.70
4	PER DIEM	105.00	$420.00
1	MILEAGE	144.60	$144.60
			$0.00
			$0.00
			$0.00
			$0.00
			$0.00
		HST	$448.80
		TOTAL	$3,901.10

Make all cheques payable to: **TOWN OF TILLSONBURG**

Net term 30 days - 1.25% per month, 15% per annum charged on overdue accounts

*****Please remit all payments to: 10 Lisgar Ave, Tillsonburg Ont, N4G 5A5*****

HYDRO GST# 863742599RT-0001

APPROVED BY: [signature]

DATE: June 17/11

W.O. #: 5100100

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	3452.30
11111	448.80

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904635958	May 07, 2011	May 29, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER **PO BOX 588 70 VICTORIA STREET, SIMCOE, ON**				
Maintenance *(PO #4671) (Contract #43186799)* - DEMAND - STORM WORK - May 1 - 6, 2011 - 37.5 hours - regular time 8 hours - overtime -	05/07/2011	6,866.50		6,866.50
Total of applied HST (105207252RT0001) taxes:			892.65	892.65
Total of current services		**6,866.50**	**892.65**	**7,759.15**

APPROVED BY:

DATE: May 26/11

W.O. # ~~5100100~~ 5100100

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	6866.50
1111	892.65

Davey info just for you

DAVEY.COM

If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY

For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

▼ Account detail ▲ Remittance advice

DAVEY
www.davey.com

Invoice

Thank you for choosing Davey!

Customer	Account number	Invoice number	Invoice date	Payment due date
NORFOLK POWER	1335756	904684530	May 26, 2011	June 12, 2011

Current services	Date of service	Cost of service	Sales tax (if applies)	Service total
NORFOLK POWER **PO BOX 588 70 VICTORIA STREET, SIMCOE, ON** Maintenance *(PO #4671) (Contract #43186799)* - DEMAND - May 18, 2011 - Owen Street, Simcoe, Hwy 3 May 20, 2011 - Lynn Valley Road -	05/20/2011	715.00		715.00
Total of applied HST (105207252RT0001) taxes:			92.95	92.95
Total of current services		**715.00**	**92.95**	**807.95**

APPROVED BY: June 1/11

DATE: 5100100

W.O. #

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100 100	715.00
11111	92.95

Davey info just for you

DAVEY.COM

If you haven't visited us online recently, take a few minutes to check out our website to learn more about Davey Tree and the services we provide. Online payment is not available for our customers at this time.

ASK DAVEY

For more information regarding Davey visit us online at www.davey.com, or contact our experts at your local office. We will be happy to help you!

Our local office:
3350 SOUTH SERVICE ROAD
Burlington ON L7N 3M6
905-333-1034

Hockley's LANDSCAPING & TREE SERVICE
101 Concession 13, RR #4, Simcoe, ON N3Y 4K3
Phone: (519) 426-1200 • Fax: (519) 426-1206
hockleylandscape@bellnet.ca

May 14, 2011

Norfolk Power
Attn: Paul Cleary
P.O. Box 588, 70 Victoria St.,
Simcoe, ON N3Y 4N6

Invoice # 2618

Location: Lynndale St. (Baldock Property)

Repair Turf Damage
10 yards of Topsoil
Seeding
Labour & Equipment — $680.00

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	680.00
11111	88.40

Sub-Total	$680.00
HST (87159 9072 RT0001)	$88.40
Amount Due	**$768.40**

APPROVED BY: ______
DATE: May 26/11
W.O. #: 5100100

Fully Insured
Graduate of Humber College

Amount Due Upon Receipt
2% Interest per month on any outstanding balances

St.Thomas energyservices
135 Edward St.
Thomas, ON 4A8
Phone: (519) 631-5550
Fax: (519) 631-4771

06-13

IM-services

Customer Number	Invoice Date	Invoice Number
191	05/20/2011	5706

Work Order	Quote Number	Purchase Order
3374		

RECEIVED
MAY 24 2011

NORFOLK POWER
70 VICTORIA ST

SIMCOE, ON N3Y 4N6

MARK BOOKER

Terms: Net 30 Days
Note: 1.5% Charged on all overdue accounts (18% per Annum)

Job Description

Description	Quantity	Rate	Total
LABOUR - LINE WORK	1.00	9593.7600	9593.76
EQUIPMENT	1.00	2853.8400	2853.84

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100-100	12 447.60
11111	1618.19

APPROVED BY: M Baker.

DATE: June 2/11

W.O. # 5100100

STORM DAMAGE

Subtotal	12447.60
HST	1618.19
Total	14065.79

Do Not Include with Hydro Bill Payment

H.S.T. #863677399 RT0001

0000125468

RECEIVED May 16/11

CORNELL FEENSTRA ELECTRIC LTD.
62848 PUTMAN ROAD, R.R. #1
WELLANDPORT, ONTARIO LOR 2J0
(905) 899-2373 Fax (905) 899-2383

CUSTOMER NO.
549

SOLD TO
NORFOLK POWER
70 VICTORIA ST.
SIMCOE ON N3Y 1L5

(519) 426-4440 Ext.

SHIP TO
NORFOLK POWER
70 VICTORIA ST.
SIMCOE ON N3Y 1L5

(519) 426-4440 Ext.

DATE	SHIP VIA	F.O.B.	TERMS
09-May-11		F.O.B. value	

PURCHASE ORDER NUMBER	ORDER DATE	SALESPERSON	OUR ORDER NUMBER
	06-May-11		0000726241

QTY. ORDERED	QTY. SHIPPED	QTY. B.O.	ITEM NUMBER	DESCRIPTION	UNIT PRICE	EXTENDED PRICE
MAY 4, 2011 - TAKE DOWN TRANSFORMER						
TM				8 8	150.00000	1,200.00
TRACK MACHINE						

WORK ORDER NO/ G.L. ACCOUNT NO.	AMOUNT
5100100	1200 00
11111	156.00

APPROVED BY:
DATE: May 25/11
W.O. # 5100100

GST Number 101154458

NET AMOUNT	1,200.00
FREIGHT	
HST	156.00
PST	
TOTAL DUE	$1,356.00

THANK YOU

Product 13501 Fold at (>) to fit Product 6481 Double Window or 6482 Single Window Envelope Printed in Canada