Oakville Hydro
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December 10, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board,
2300 Yonge St.
Suite 2700, P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: OEB File No. EB-2010-0104
Oakville Hydro Electricity Distribution Inc.
2011 Distribution Rate Adjustment Application

Please find enclosed, Oakville Hydro Electricity Distribution Inc.'s responses to the School Energy Coalition's interrogatories in the above noted proceeding.

Should there be any questions, please do not hesitate to contact me.

Respectfully submitted,

Maryanne Wilson

Maryanne Wilson
Manager, Regulatory Affairs
Oakville Hydro Electricity Distribution Inc.
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IN THE MATTER of the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Oakville Hydro Electricity Distribution Inc. for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective on May 1, 2011.

Oakville Hydro Electricity Distribution Inc. (OHEDI)
Responses to Interrogatories
School Energy Coalition (SEC)
EB-2010-0104
Filed: December 10, 2010

Contents

1. [General] Please advise the actions the Applicant will take in the event that the Board does not approve the incremental capital module applied for.

RESPONSE

Please see response to Board Staff interrogatory number 9 (b).

2. [p. 11] Please confirm that the 2010 capital expenditures budget of the Applicant of $14,721,227 did not include any expenditures directly or indirectly related to the proposed Oakville MTS #1. Please identify and quantify all OM&A and other expenditures included in the 2010 revenue requirement related to the proposed Oakville MTS #1, including personnel, consulting, feasibility, pre-approval, and other costs of all types.

RESPONSE

OHEDI's 2010 capital expenditures budget of $14,721,227 did not include any expenditures directly or indirectly related to the proposed Oakville MTS #1. OHEDI's 2010 revenue requirement did not include any OM&A expenditures for the Oakville MTS #1.

3. [p. 18] With respect to the capital spending table:

a. Please confirm that none of the amounts of $445,703 and $12,762,816 have been or will be included in rate base prior to January 1, 2011.

RESPONSE

OHEDI has not included the amount of $445,703 and $12,762,816 in its rate base and will not do so prior to January 1, 2011.

b. Please advise the amount spent to date, by category, in the 2010 Bridge Year, and any changes to the 2010 Bridge Year spending forecast.

RESPONSE

Oakville Hydro Distribution Inc
Transfomer Station Budget

Component	2009 Actual	Costs Incurred to Nov 12,2010	Costs still to be Rec'd in 2010	Total 2010 Bridge Year	2011 Test Year	Total
Substation Equipment	46,702	580,262	380,869	961,130	1,081,975	2,089,807
TS Switchgear - Gas	124,456	2,094,011	-	2,094,011	914,408	3,132,875
TS Transformer	251,975	951,051	1,577,150	2,528,201	3,680,818	6,460,994
Revenue Meters	17,460	25,849	263,402	289,251	156,720	463,431
SCADA & DC Systems	5,348	7,235	94,291	101,527	27,755	134,630
UG Cable	-	50,890	115,336	166,226	117,250	283,476
Duct & Civil	-	415,366	850,584	1,265,950	695,533	1,961,483
Building	-	1,180,451	1,396,900	2,577,351	1,818,064	4,395,414
Land	-	1,360,619	7,081	1,367,700	-	1,367,700
Construction Contingency					720,000	720,000
HV Commissioning		-	-		110,000	110,000
CCRA Capital Contribution	-	120,200		120,200	120,200	240,400
Total	**445,940**	**6,785,934**	**4,685,612**	**11,471,546**	**9,442,723**	**21,360,209**

c. Please restate the current forecast of $20,488,489 using the categories contained in the document (Unnumbered page at the beginning of Appendix 7 - bottom total $20,493,000) entitled "Oakville MTS #1 – Project Budget" attached to the Costello Associates study, and provide a side by side comparison of the two referenced budgets. Please provide an explanation of any material differences between any component in the two budgets.

RESPONSE

Oakville MTS #1 - Project Budget					
		Costello Study Estimates		Restated 2010-12-09	
	Component	**Cost Detail**	**Summary**	**Cost Detail**	**Summary**
1	**Property Costs**	$ 1,800,000		$ 1,367,700	
			$ 1,800,000		**$ 1,367,700**
2	**Engineering & Design**				
	Preliminary engineering	$ 20,000		$ 35,012	
	Impact Assessments and Fees	$ 80,000		$ 360,466	
	Environmental Assessment	$ 100,000		$ 116,271	
	Soils & Grounding	$ 40,000		$ 30,000	
	Detailed engineering & Design	$ 700,000		$ 818,430	
	Site Supervision	$ 100,000		$ 77,733	
			$ 1,040,000		**$ 1,437,912**
3	**Major equipment**				
	Transformers	$ 7,000,000		$ 6,460,994	
	Switchgear	$ 2,500,000		$ 3,132,875	
	Protecion and Control	$ 700,000		$ 910,934	
	230 kV Switches	$ 70,000		$ 110,038	
	Grounding Reactors	$ 60,000		$ 69,100	
	DC System	$ 60,000		$ 115,500	
	Primary Metering	$ 200,000		$ 463,431	
	Capacitor Banks	$ 250,000		$ -	
	Feeders	$ 480,000		$ 563,703	
			$ 10,590,000		**$ 11,262,871**
4	**Civil Construction**				
	Mobilization	$ 50,000		$ 104,190	
	Yard Structures	$ 80,000		$ 290,702	
	Switchgear Building	$ 1,200,000		$ 1,644,127	
	Oil Containment	$ 150,000		$ 63,247	
	Duct Banks	$ 360,000		$ 1,503,432	
	Concrete Foundations	$ 20,000		$ 32,300	
	Fence & Stone	$ 50,000		$ 90,549	
	Other	$ 650,000		$ 1,248,598	
			$ 2,560,000		**$ 4,977,144**
5	**Electrical**				
	Grounding	$ 50,000		$ 269,124	
	230 kV Busswork	$ 200,000		$ 163,051	
	Station Service	$ 200,000		$ 220,399	
	Control Cabling	$ 240,000		$ 211,672	
	Cable Pulling and Termination	$ 120,000		$ 182,111	
	Commissioning	$ 150,000		$ 110,000	
	Other	$ 300,000		$ 438,224	
			$ 1,260,000		**$ 1,594,581**
	Sub-Total		$ 17,250,000		$ 20,640,209
	Contingency		$ 1,725,000		$ 720,000
	Total		**$ 18,975,000**		**$ 21,360,209**
	PST (8%)		$ 1,518,000		$ -
	Budget Amount		**$ 20,493,000**		**$ 21,360,209**

Material differences between the "Oakville MTS #1 – Project Budget" included the Costello Study appendix 7 and the rested budget dated November 18th 2010 are as follows:

1. The original Costello Study budget did not include any capital contribution costs required by Hydro One. Per the attached Hydro One Connection and Cost Recovery Agreement attached, there is a capital contribution of $240,400 required for chargeable work. This has been included in the restated budget under Engineering & Design – Impact Assessments and Fees.

2. The original Costello Study budget line item for Major equipment – Primary Metering was adequate to determine the feasibility of the project, but fell short on reflecting the actual costs. In the restated budget this line item includes the equipment costs for instrument transformers (6 units planned to be in service and 1 additional spare unit) in addition to Meter Service Provider costs.

3. The original Costello Study budget was based on the assumption that the site would be adjacent to a roadway, but the owner of the lands identified as the preferred site in our Environmental Assessment was not willing to sell the parcel of land adjacent to 6th Line. Instead, we purchased a parcel of land set back into the preferred site and a 300m long strip of land to be used as an access roadway and ductbank corridor. The cost associated with constructing the access roadway and associated ductbanks is $1,065,000.00. The storm water management requirements for our site to prevent soil erosion on the adjacent property increased the construction costs by $340,000. Additional premiums associated with topsoil removal, rain water management during construction, and general site access challenges associated with the location of our land parcel have caused an increase in civil costs of approximately 10% - 15% with respect to the Costello Study budget.

4. Hydro One did not allow us to rely on our connection to the "skywire" grounding system per page 26, section 8.4, part R8.4.1 of the following document for "Functional Requirement for New Transmission Load Connections" provided in Appendix 1. This is a new document created November 2008. The additional grounding requirements increased the budget line item for Electrical – Grounding by approximately $125,000.

5. The original Costello Study budget carried a contingency valued at 10% of the total budget. With the majority of equipment costs determined via firm price contracts we have reduced this contingency down to $720,000. This contingency allowance is expected to compensate for site condition variances and design changes during the construction phase

6. The original Costello Study budget carried an additional 8% for PST, but with the adoption of HST taxes are no longer capitalized.

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4. [Appendix A] With respect to this evidence:

a. P. 47. Please identify the subject matter of the legal advice provided to the Applicant by its counsel related to Transformer Stations Supply Options. Please confirm that all persons drafting and/or giving that advice were members of the Law Society of Upper Canada. If any of that advice was not given by and prepared solely by members of the Law Society of Upper Canada duly qualified to practice law in Ontario, please provide that portion of the advice unredacted. With respect to all of the advice on which solicitor-client confidentiality is claimed, please provide a full unredacted copy to the Board (and not to the parties) for review.

RESPONSE

Please see OHEDI's response to Board Staff Interrogatory number 20.

b. P. 48. Please identify the "Agreements" referred to in the second paragraph, and relate the answer to the "cost estimates" on which confidentiality is sought. Please advise whether the Applicant has entered into any agreements with Hydro One with respect to either of the Hydro One transformer options discussed in the Application, and if so provide those agreements.

RESPONSE:

The "Agreements" referred to in the second paragraph refers to documents provided by Hydro One regarding their estimated costs to construct the North Oakville TS. These documents did not consist of formal agreements.

OHEDI has entered into a connection and cost recovery agreement with Hydro One for the construction of a 230 kV line connection to OHEDI's new MTS from Hydro One's

230 kV circuits, T36B and T37B. A copy of the agreement is provided as Appendix 8 of Oakville Hydro's response to Board Staff interrogatories.

5. [Costello Study, p. 7] Please provide all communications with Hydro One with respect to the "systemic problem" referred to.

RESPONSE

This information was filed with the Board in confidence as part of the materials that were considered to contain confidential material. The confidentiality request should have been worded to state that the details of cost estimates and other materials provided in confidence to OHEDI by Hydro One.

OHEDI is prepared to provide copies to parties' counsel and experts or consultants provided that they have executed the Board's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to OHEDI's right to object to the Board's acceptance of a declaration and undertaking from any person.

6. [Costello Study, pp. 13 and 19] Please provide a copy of the "brief" Hydro One proposal for two options for a North Oakville TS, together with any supporting documentation or communications providing any additional details.

RESPONSE

The Hydro One proposal can be found in Appendix 3 of the Costello Study and has been provided as Appendix 2 for the convenience of the parties in this proceeding.

7. [Costello Study, p. 16] Please provide details and sources supporting the statement "LDC's typically build municipal transformer stations for significantly less cost than Hydro One. Historically LDC cost savings were in the range of 20-30%, however with recent pricing from Hydro One, the savings are even greater".

RESPONSE

This statement is based on Costello Associates direct experience with several municipal transformer station projects between 2004 - 2010, and also based on common industry knowledge. Costello Associates has advised OHEDI that they are unable to release specific project details due to confidentiality requirements with their clients.

8. [Costello Study, p. 22] With respect to the comparison between the Hydro One North Oakville TS option and the proposed Oakville MTS #1 option:

a. Please describe any differences in the expected lifetime of the two stations.

RESPONSE

There is no difference in the expected lifetime of the two stations.

b. Please estimate the percentage of the capital cost of each of the Hydro One station and the new Oakville MTS #1 that is expected to be expended on:

i. Labour costs (all compensation, without any overheads) of employees of the Applicant, or

RESPONSE

OHEDI has budgeted labour and benefits for its employees in this project. Estimated percentage of the capital cost of the new Oakville MTS #1 would be 0.51%.

ii. Labour costs (all compensation, without any overheads) of employees of Hydro One.

RESPONSE

OHEDI does not have enough information to estimate the percentage of labour costs of Hydro One employees for each of the Hydro One stations and the new Oakville MTS #1.

c. Please estimate the average total compensation per union employee of the Applicant in the Test Year. Please include in the total the averages of base wages, overtime, incentives, and benefits as set forth in Appendix 2-K of the Filing Guidelines for cost of service applications. If the Applicant has any comparisons of the average total compensation per union employee of the Applicant relative to Hydro One, please provide those comparisons.

RESPONSE

The annual average compensation including benefits and overtime for OHEDI is $98,055 per year. OHEDI does not have information for Hydro One employee rates.

9. [Costello Study, p. 23] Please provide a spreadsheet that shows the rate contribution of incremental load to the cost of the proposed new Oakville MTS #1, relative to the annual impact on rates, by providing, for each year commencing in 2011:

a. The expected annual costs included in rates from the new Oakville MTS #1, including amortization, cost of capital, PILs, O&M, and any other cost impacts. A breakdown of costs is not necessary, as long as all are included.

RESPONSE

The following table provides the expected annual costs included in rates from the Oakville MTS#1 including amortization, cost of capital, PILs, O&M along with the incremental revenues from rates in the area served by the new Oakville MTS#1. OHEDI's approved cost of capital of 7.31% was used as the discount rate.

Oakville MTS #1

Cost Revenue Analysis

Year	Costs	Revenue	Revenue - Costs	Accumulated Revenue - Costs	PV of Revenue - Costs	PV of Accumulated Revenue - Costs
2011	$2,016,655	$129,881	-$1,886,774	-$1,886,774	-$1,758,247	-$1,758,247
2012	$2,149,067	$332,441	-$1,816,625	-$3,703,400	-$1,577,556	-$3,216,031
2013	$2,272,857	$550,492	-$1,722,366	-$5,425,765	-$1,393,814	-$4,390,767
2014	$2,390,503	$1,410,278	-$980,225	-$6,405,991	-$739,205	-$4,830,872
2015	$2,505,071	$2,760,099	$255,028	-$6,150,963	$179,220	-$4,322,571
2016	$2,501,724	$3,428,941	$927,217	-$5,223,745	$607,212	-$3,420,904
2017	$2,569,873	$3,723,987	$1,154,114	-$4,069,632	$704,316	-$2,483,555
2018	$2,635,284	$4,246,849	$1,611,566	-$2,458,066	$916,487	-$1,397,887
2019	$2,698,266	$4,769,712	$2,071,445	-$386,621	$1,097,771	-$204,891
2020	$2,759,067	$5,292,575	$2,533,508	$2,146,887	$1,251,182	$1,060,248
2021	$2,817,846	$5,815,361	$2,997,514	$5,144,402	$1,379,492	$2,367,515
2022	$2,817,035	$6,165,052	$3,348,017	$8,492,419	$1,435,838	$3,642,076
2023	$2,814,575	$6,337,474	$3,522,899	$12,015,318	$1,407,919	$4,801,896
2024	$2,810,605	$6,505,625	$3,695,019	$15,710,337	$1,376,113	$5,850,901
2025	$2,805,251	$6,673,775	$3,868,524	$19,578,861	$1,342,587	$6,794,923
2026	$2,798,627	$6,841,925	$4,043,298	$23,622,160	$1,307,653	$7,639,703
2027	$2,790,837	$7,013,963	$4,223,126	$27,845,286	$1,272,772	$8,392,056
2028	$2,781,978	$7,186,377	$4,404,398	$32,249,684	$1,236,981	$9,057,367
2029	$2,772,138	$7,354,527	$4,582,389	$36,832,072	$1,199,301	$9,639,676
2030	$2,761,398	$7,522,677	$4,761,279	$41,593,351	$1,161,234	$10,144,252
2031	$2,749,800	$7,695,031	$4,945,231	$46,538,582	$1,123,938	$10,577,160
2032	2,722,416	$7,822,038	$5,099,623	$51,638,205	$1,080,075	$10,936,714
2033	2,694,464	$7,900,259	$5,205,794	$56,843,999	$1,027,454	$11,219,155
2034	2,666,006	$7,979,261	$5,313,255	$62,157,254	$977,228	$11,432,130
2035	2,637,096	$8,059,054	$5,421,958	$67,579,211	$929,290	$11,582,658

b. The portion allocated to TS of the expected annual incremental revenues from rates in the area served by the new Oakville MTS#1, under the current growth assumptions. Please describe any simplifying assumptions used, and provide an estimate of the impact of any load growth sensitivity analyses that have been developed.

RESPONSE

Please see response to part (a) of this interrogatory. The number of residential customers served by the new Oakville MTS#1 is based upon OHEDI's estimate of the number of new homes in the North Oakville Area in 2011 to 2014 and the Town of Oakville's forecast of the number of new homes in the North Oakville for 2016 onwards as provided in the table below.

It is assumed that growth will be spread equally over each of the forecasted intervals (e.g. the growth of 5,264 between 2016 and 2021 has been allocated equally 2017, 2018, 2019, 2020 and 2021. The forecast includes a 2% increase in residential customer numbers after 2031.

North Oakville Housing Units	
2011	738
2016	6,968
2021	12,232
2031	15,649

The number of general service customers is estimated based on the current proportion of general service customers to residential customers recognizing that commercial growth will lag behind residential growth in the first few years of the development of the North Oakville arera. Revenue estimates are based on current rates.

c. The net amount of the shortfall in incremental annual cost borne by today's customers, identifying the crossover year.

RESPONSE

Please see response to part (a) of this question. The crossover years are 2015 and 2020.

10. [Costello Study, p. 24] Please provide a numerical example showing how the additional borrowing for the proposed TS would "increase the overall return to the shareholder as the corporation increases leverage at a cheaper rate".

RESPONSE

This comment is describing the situation that based on the time of the report, OHEDI actual equity and debt ratios were not at the OEB deemed rates as shown below. By borrowing to build this asset, OHEDI will bring its debt equity structure closer to the Board deemed structure and this will have the impact of increasing the organizations levered return on equity.

	2008 Audited Results	OEB Deemed Rates	2008 Audited Results with TS loan at $20M
Debt	67,946		87,946
Equity	54,214		54,214
Total Debt & Equity	122,160		142,160
Debt %	56%	60%	61%
Equity %	44%	40%	39%

11. [Costello Study, p. 35] Please provide examples, with sources, supporting each of the following statements:

a. "There have however been several cases where Hydro One has allowed load growth to exceed the capability of the station ratings".

RESPONSE

There are two cases referenced in Section 2.4 of the Costello Associates report. Norfolk TS, located in Simcoe, was operating 40-50% over its published rating for several years. In the summer of 2001, there was a transformer failure at the station and Hydro One initiated rotating blackouts for several days.

The other case mentioned in the report is from the same time period at Beamsville TS. The station was operating above its published rating and there was a transformer failure. No blackouts occurred, but emergency measures were implemented to prevent outages.

b. ""Hydro One recovers their regulated transmission tariff based on the loading of the facility, so it could be argued that there is a financial benefit to operating stations beyond their capacity".

RESPONSE

Hydro One charges transmission-connected load customers based on the monthly peak demand of each supply point. Hydro One's revenue increases as more and more load is placed on a transformer station.

c. "LDCs have taken the position that system reliability has been compromised by the age, condition, or loading at existing Hydro One stations".

RESPONSE

Over the past ten years, many LDC's facing capacity shortages have elected to build their first municipal transformer station as opposed to having Hydro One expand existing or construct new facilities. The LDC decision to invest in these assets is typically based on both economic and technical factors, including the reliability of the existing station supplies.

12. [Costello Study, p. 36] Please advise the costs in 2010 and 2011 associated with "specialized training" and "new operational procedures", and identify where, if at all, any of those costs are included in the Board-approved OM&A for 2010. Please confirm that none of the costs associated with training, changes in operational procedures, upgrading of IT capability, or any similar charges are included in the capital budget of the proposed new Oakville MTS #1.

RESPONSE

OHEDI confirms that there are no costs for "specialized training" and "new operational procedures" included in the Board approved OM&A for 2010. OHEDI also confirms that there are no costs associated with training, changes in operational procedures, upgrading of IT capability or any similar charges included in the capital budget of the proposed new Oakville MTS#1. We have included $ 30k in 2011 OM&A costs for new operational procedures and associated staff training.

13. [Costello Study, p. 41 and following] Please reproduce the project Gantt chart for the proposed Oakville MTS #1, identifying for each task the current status of the work on that task (i.e. where on timeline is the work right now), and any changes required to the forecast completion of each task that is not currently complete. Please confirm that the "aggressive" in-service date prior to the summer of 2011 is still expected to be achieved. If any of the tasks are behind schedule, please describe the actions to be taken to get the project back on schedule.

RESPONSE

Please see OHEDI's response to Board Staff interrogatory number 18.

14. [Costello Study, Appendix 7] With respect to this Appendix:

a. Please explain the figure of ($5,383,709.08) on the line "NPV of Shareholder Return" on the page entitled "Approximate Present Value of Shareholder Return", and show in detail how it is calculated. If that figure is the NPV prior to taking "OM&A" into account, please confirm that the column OMA includes only amortization, and not any of the annual operating costs of the station.

RESPONSE

The $(5,383,709.08) on the line "NPV of Shareholder Return" is identified and explained in more detail in the Table attached. This NPV is not taking into account "OM&A". OHEDI confirms that the column OMA includes only amortization and not any annual operating costs.

Assumptions:		WACC			7.2%	(Debt 6% at 60%, Equity at 9% at 40%)	
		Depreciation			2.5%		
		Discount Rate			6.0%		

	Single Station - Oakville Alone					OMA	
Year	Gross Asset Value	Accum Depreciation	NBV (a)	WACC (b)	Captial Revenue Req't (c)= (a)*(b)	(includes amortization only)	Total Recovered
2008							
2009							
2010							
2011					$ (20,493,000.00)		$ (20,493,000.00)
2012	20,493,000.00	512,325.00	19,980,675.00	7.2%	$ 1,438,608.60	$ 512,325.00	$ 1,950,933.60
2013	20,493,000.00	1,024,650.00	19,468,350.00	7.2%	$ 1,401,721.20	$ 512,325.00	$ 1,914,046.20
2014	20,493,000.00	1,536,975.00	18,956,025.00	7.2%	$ 1,364,833.80	$ 512,325.00	$ 1,877,158.80
2015	20,493,000.00	2,049,300.00	18,443,700.00	7.2%	$ 1,327,946.40	$ 512,325.00	$ 1,840,271.40
2016	20,493,000.00	2,561,625.00	17,931,375.00	7.2%	$ 1,291,059.00	$ 512,325.00	$ 1,803,384.00
2017	20,493,000.00	3,073,950.00	17,419,050.00	7.2%	$ 1,254,171.60	$ 512,325.00	$ 1,766,496.60
2018	20,493,000.00	3,586,275.00	16,906,725.00	7.2%	$ 1,217,284.20	$ 512,325.00	$ 1,729,609.20
2019	20,493,000.00	4,098,600.00	16,394,400.00	7.2%	$ 1,180,396.80	$ 512,325.00	$ 1,692,721.80
2020	20,493,000.00	4,610,925.00	15,882,075.00	7.2%	$ 1,143,509.40	$ 512,325.00	$ 1,655,834.40
2021	20,493,000.00	5,123,250.00	15,369,750.00	7.2%	$ 1,106,622.00	$ 512,325.00	$ 1,618,947.00
2022	20,493,000.00	5,635,575.00	14,857,425.00	7.2%	$ 1,069,734.60	$ 512,325.00	$ 1,582,059.60
2023	20,493,000.00	6,147,900.00	14,345,100.00	7.2%	$ 1,032,847.20	$ 512,325.00	$ 1,545,172.20
2024	20,493,000.00	6,660,225.00	13,832,775.00	7.2%	$ 995,959.80	$ 512,325.00	$ 1,508,284.80
2025	20,493,000.00	7,172,550.00	13,320,450.00	7.2%	$ 959,072.40	$ 512,325.00	$ 1,471,397.40
2026	20,493,000.00	7,684,875.00	12,808,125.00	7.2%	$ 922,185.00	$ 512,325.00	$ 1,434,510.00
2027	20,493,000.00	8,197,200.00	12,295,800.00	7.2%	$ 885,297.60	$ 512,325.00	$ 1,397,622.60
2028	20,493,000.00	8,709,525.00	11,783,475.00	7.2%	$ 848,410.20	$ 512,325.00	$ 1,360,735.20
2029	20,493,000.00	9,221,850.00	11,271,150.00	7.2%	$ 811,522.80	$ 512,325.00	$ 1,323,847.80
2030	20,493,000.00	9,734,175.00	10,758,825.00	7.2%	$ 774,635.40	$ 512,325.00	$ 1,286,960.40
2031	20,493,000.00	10,246,500.00	10,246,500.00	7.2%	$ 737,748.00	$ 512,325.00	$ 1,250,073.00
2032	20,493,000.00	10,758,825.00	9,734,175.00	7.2%	$ 700,860.60	$ 512,325.00	$ 1,213,185.60
2033	20,493,000.00	11,271,150.00	9,221,850.00	7.2%	$ 663,973.20	$ 512,325.00	$ 1,176,298.20
2034	20,493,000.00	11,783,475.00	8,709,525.00	7.2%	$ 627,085.80	$ 512,325.00	$ 1,139,410.80
2035	20,493,000.00	12,295,800.00	8,197,200.00	7.2%	$ 590,198.40	$ 512,325.00	$ 1,102,523.40
2036	20,493,000.00	12,808,125.00	7,684,875.00	7.2%	$ 553,311.00	$ 512,325.00	$ 1,065,636.00
2037	20,493,000.00	13,320,450.00	7,172,550.00	7.2%	$ 516,423.60	$ 512,325.00	$ 1,028,748.60
2038	20,493,000.00	13,832,775.00	6,660,225.00	7.2%	$ 479,536.20	$ 512,325.00	$ 991,861.20
2039	20,493,000.00	14,345,100.00	6,147,900.00	7.2%	$ 442,648.80	$ 512,325.00	$ 954,973.80
2040	20,493,000.00	14,857,425.00	5,635,575.00	7.2%	$ 405,761.40	$ 512,325.00	$ 918,086.40
2041	20,493,000.00	15,369,750.00	5,123,250.00	7.2%	$ 368,874.00	$ 512,325.00	$ 881,199.00
2042	20,493,000.00	15,882,075.00	4,610,925.00	7.2%	$ 331,986.60	$ 512,325.00	$ 844,311.60
2043	20,493,000.00	16,394,400.00	4,098,600.00	7.2%	$ 295,099.20	$ 512,325.00	$ 807,424.20
2044	20,493,000.00	16,906,725.00	3,586,275.00	7.2%	$ 258,211.80	$ 512,325.00	$ 770,536.80
2045	20,493,000.00	17,419,050.00	3,073,950.00	7.2%	$ 221,324.40	$ 512,325.00	$ 733,649.40
2046	20,493,000.00	17,931,375.00	2,561,625.00	7.2%	$ 184,437.00	$ 512,325.00	$ 696,762.00
2047	20,493,000.00	18,443,700.00	2,049,300.00	7.2%	$ 147,549.60	$ 512,325.00	$ 659,874.60
2048	20,493,000.00	18,956,025.00	1,536,975.00	7.2%	$ 110,662.20	$ 512,325.00	$ 622,987.20
2049	20,493,000.00	19,468,350.00	1,024,650.00	7.2%	$ 73,774.80	$ 512,325.00	$ 586,099.80
2050	20,493,000.00	19,980,675.00	512,325.00	7.2%	$ 36,887.40	$ 512,325.00	$ 549,212.40
2051	20,493,000.00	20,493,000.00	-		$ -	$ 512,325.00	$ 512,325.00
Gross Shareholder Return					$ 8,279,172.00		$ 28,772,172.00
NPV of Shareholder Return (represents sum of column (c), net present valued at the discount rate of 6.0%)					($5,383,709.08)		$1,888,549.45

OMA- includes only depreciation

b. Please confirm that the NPV figures in the same table do not include any impact on working capital.

RESPONSE

OHEDI confirms that the NPV figures in the table provided in our response above in 14 (a) do not include any impact on working capital.

c. Please advise the debt rate assumed in the same table.

RESPONSE

The weighted average cost of capital rate assumed in the table is 7.2%.

d. Please advise whether the distribution rate impact of 9.95% for residential customers on the page marked "Oakville only – Option 1 – TS + Lines" is the impact for 2011 only, the impact once the full costs are included in rates, an average impact, or some other amount. Please confirm that the table does not include the impact of incremental loads. Please prepare a similar table for GS >50KW customers.

RESPONSE

The distribution rate impact of 9.95% is the 2011 impact of the total costs of the transformer station including the cost of the feeders, OM&A and PILs. Although the feeders are directly related to the construction of the new TS, OHEDI did not include the cost of the feeders in its incremental capital claim. The table does not include the impact of incremental load.

A similar table is provided for both Residential and General Service > 50 kW rate classes below. The tables have been updated to reflect the incremental capital claim submitted in this proceeding as compared to 2010 approved rates rather than 2009 approved rates.

Consumption	**1,000**	**kWh**	**-**	**kW**		***Loss Factor***	***1.0377***	
RPP Tier One	**600**	**kWh**	***Load Factor***	***40.0%***				

Residential	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	31.59%
Energy Second Tier (kWh)	231	0.0750	17.33	231	0.0750	17.33	0.00	0.0%	14.04%
Sub-Total: Energy			**56.33**			**56.33**	**0.00**	**0.0%**	**45.63%**
Service Charge	1	13.25	13.25	1	13.25	13.25	0.00	0.0%	10.73%
Service Charge Rate Adder(s)	1	1.69	1.69	1	1.69	1.69	0.00	0.0%	1.37%
Service Charge Rate Rider(s)	1,000	0.00	0.00	1,000	0	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate	1,000	0.0145	14.50	1,000	0.0164	16.40	1.90	13.1%	13.29%
Distribution Volumetric Rate Adder(s)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	0.0%	0.00%
Low Voltage Volumetric Rate	1,000	0.0002	0.20	1,000	0.0002	0.20	0.00	0.0%	0.16%
Total: Distribution			**29.64**			**31.54**	**1.90**	**6.4%**	**25.55%**
Retail Transmission Rate – Network Service Rate	831	0.0055	4.57	831	0.0055	4.57	0.00	0.0%	3.70%
Retail Transmission Rate – Line and Transformation Connection Service Rate	831	0.0046	3.82	831	0.0046	3.82	0.00	0.0%	3.09%
Retail Transmission Rate – Low Voltage Volumetric Rate	831	0.0000	0.00	831	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**8.39**			**8.39**	**0.00**	**0.0%**	**6.80%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**38.03**			**39.93**	**1.90**	**5.0%**	**32.35%**
Wholesale Market Service Rate	831	0.0052	4.32	831	0.0052	4.32	0.00	0.0%	3.50%
Rural Rate Protection Charge	831	0.0013	1.08	831	0.0013	1.08	0.00	0.0%	0.87%
Special Purpose Charge	831	0.0004	0.33	831	0.0004	0.33	0.00	0.0%	0.27%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.20%
Sub-Total: Regulatory			**5.98**			**5.98**	**0.00**	**0.0%**	**4.84%**
Debt Retirement Charge (DRC)	1,000	0.00700	**7.00**	1,000	0.00700	**7.00**	**0.00**	**0.0%**	5.67%
Total Bill before Taxes			**107.34**			**109.24**	**1.90**	**1.8%**	**88.50%**
HST	107.34	13%	**13.95**	109.24	13%	**14.20**	**0.25**	**1.8%**	**11.50%**
Total Bill			**121.29**			**123.44**	**2.15**	**1.8%**	**100.00%**

Consumption	**140,000**	**kWh**	**480**	**kW**		***Loss Factor***	***1.0377***	
RPP Tier One	**750**	**kWh**	***Load Factor***	***40.0%***				

GS > 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.0%	0.26%
Energy Second Tier (kWh)	144,528	0.0750	10,839.60	144,528	0.0750	10,839.60	0.00	0.0%	57.93%
Sub-Total: Energy			**10,888.35**			**10,888.35**	**0.00**	**0.0%**	**58.19%**
Service Charge	1	116.64	116.64	1	116.64	116.64	0.00	0.0%	0.62%
Service Charge Rate Adder(s)	1	1.69	1.69	1	1.69	1.69	0.00	0.0%	0.01%
Service Charge Rate Rider(s)	480	0.00	0.00	1	0	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate	480	3.6216	1,738.37	480	3.8823	1,863.50	125.13	7.2%	9.96%
Distribution Volumetric Rate Adder(s)	480	0.0000	0.00	480	0.0000	0.00	0.00	0.0%	0.00%
Low Voltage Volumetric Rate	480	0.0638	30.62	480	0.0638	30.62	0.00	0.0%	0.16%
Total: Distribution			**1,887.32**			**2,012.45**	**125.13**	**6.6%**	**10.75%**
Retail Transmission Rate – Network Service Rate	480	1.9161	919.73	480	1.9161	919.73	0.00	0.0%	4.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	480	1.5762	756.58	480	1.5762	756.58	0.00	0.0%	4.04%
Retail Transmission Rate – Low Voltage Volumetric Rate	480	0.0000	0.00	480	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**1,676.31**			**1,676.31**	**0.00**	**0.0%**	**8.96%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**3,563.63**			**3,688.76**	**125.13**	**3.5%**	**19.71%**
Wholesale Market Service Rate	145,278	0.0052	755.45	145,278	0.0052	755.45	0.00	0.0%	4.04%
Rural Rate Protection Charge	145,278	0.0013	188.86	145,278	0.0013	188.86	0.00	0.0%	1.01%
Special Purpose Charge	145,278	0.0004	58.11	145,278	0.0004	58.11	0.00	0.0%	0.31%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**1,002.67**			**1,002.67**	**0.00**	**0.0%**	**5.36%**
Debt Retirement Charge (DRC)	140,000	0.00700	**980.00**	140,000	0.00700	**980.00**	**0.00**	**0.0%**	5.24%
Total Bill before Taxes			**16,434.65**			**16,559.78**	**125.13**	**0.8%**	**88.50%**
HST	16,434.65	13%	**2,136.50**	16,559.78	13%	**2,152.77**	**16.27**	**0.8%**	**11.50%**
Total Bill			**18,571.15**			**18,712.55**	**141.40**	**0.8%**	**100.00%**

Appendix 1

Requirement for New Transmission Load Connections

FUNCTIONAL REQUIREMENTS FOR NEW TRANSMISSION LOAD CONNECTIONS

LIMITATION OF LIABILITY AND DISCLAIMER

Neither Hydro One Networks Inc. nor any person employed on its behalf makes any warranty, or representation whatsoever, expressed or implied, or assumes any responsibility for the accuracy, adequacy, or completeness of the information contained in this document, or accepts any liability for the use, or damages, either directly, consequentially, or otherwise, resulting from the use thereof or reliance thereon.

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DATE:	November 26, 2008	March 13, 2009	March 20, 2009

REVISION HISTORY

DATE	VERSION	COMMENTS
November 2008	R0	New document – John Ciufo

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1.0 INTRODUCTION AND PURPOSE

The *Transmission System Code* (**"TSC"**) issued by the Ontario Energy Board ("**OEB"**) on July 25, 2005 gives customers three options for the construction and ownership of new load connection facilities.

The connection applicant may elect to:

1. request Hydro One Networks Inc. ("**Hydro One"**) to construct and own all new load connection facilities and the connection applicant shall pay a capital contribution where required;

2. construct all of the new load connection facilities identified as contestable work and transfer ownership of specific elements to Hydro One; or

3. construct and own the new load connection facilities identified as contestable work.

All three of the above options require that the design and construction methodologies for the load connection facilities meet the requirements set out in the TSC. For option 1, these requirements shall be met through the use of Hydro One's internal design and construction practices.

For option 2, the TSC requirements shall be met through the use of Hydro One's project technical requirements which Hydro One shall provide to the load customer. For option 3, the TSC requirements shall be met by complying with Hydro One's load connection interface requirements, and industry practices and standards.

The TSC sets out the minimum generic requirements for connecting new loads to the transmission system in a manner that does not materially reduce the reliability or performance of the transmission system or cause a material negative impact on another customer connected to the transmission system. The purpose of this document is to describe Hydro One's functional requirements to provide guidance for customers contemplating a new load connection to Hydro One's transmission system.

The functional requirements presented are applicable to load facilities that are intended to be connected (tapped) to Hydro One's Transmission system (115 kV and above). They do not apply to terminal type stations.

Organization of this Document

The format of these Functional Requirements for New Transmission Load Connections closely follows the format of the TSC wherever possible.

Sections 1 through 13 of these Functional Requirements for New Transmission Load Connection are aligned with the TSC. Hydro One has attempted to avoid repetition of the requirements set out in the TSC. However, in some cases, TSC requirement(s) have been repeated to underscore those particular needs.

In general, Sections 1 through 13 of the Functional Requirements for New Transmission Load Connections clarify and supplement the requirements set out in the TSC. Where applicable, each section includes further details for customers who select Option 2. All additional sub-sections sections are highlighted in yellow for ease of identification.

Section 14 of this document has been provided for customers who select Option 2 for their load connection facilities and includes functional requirements not addressed in the TSC. In accordance with Hydro One's OEB-approved Connection Process. Load customers who proceed with Option 2 shall be provided with a separate set of technical requirements upon executing an appropriate confidentiality agreement.

Requirements that must be met by all Load Connection Stations ("LCS") are numbered with a preceding letter R, the corresponding Section number and the requirement sequence number (e.g. R1.1).

Requirements that apply only to LCSs for which ownership will be transferred to Hydro One are numbered with a preceding letter H, the corresponding Section number and the requirement sequence number (e.g. H1.1).

Conflict with the Transmission System Code or the OEB-Approved Connection Procedures

These Functional Requirements for New Transmission Load Connections are subject to the TSC and Hydro One's OEB-Approved Connection Procedures. If any provision of these Functional Requirements is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new load connection facilities, on the same subject matter, the TCA governs.

1.1 LIST OF SUPPORTING DOCUMENTS

1.1.1 OEB Documents

The requirements for a new load connection to the transmission system are set out in the TSC (available at: www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms) including particular technical requirements set out in the FORM OF CONNECTION AGREEMENT FOR LOAD CUSTOMERS attached to the TSC as Appendix I Version A (the "**Connection Agreement**" or "**TCA"**).

1.1.2 Agreements with Hydro One

All Load Customers planning to connect to Hydro One's Transmission System must complete a Connection Application and execute a Connection and Cost Recovery Agreement ("**CCRA**").

Both documents are available to customers at Hydro One's web site (www.HydroOne.com). Prior to actual connection, load customers shall be required to enter into a Connection Agreement with Hydro One.

To assist customers in understanding the overall customer connection requirements, the diagram below (Figure 1) lists the relationship between the various codes and documents.

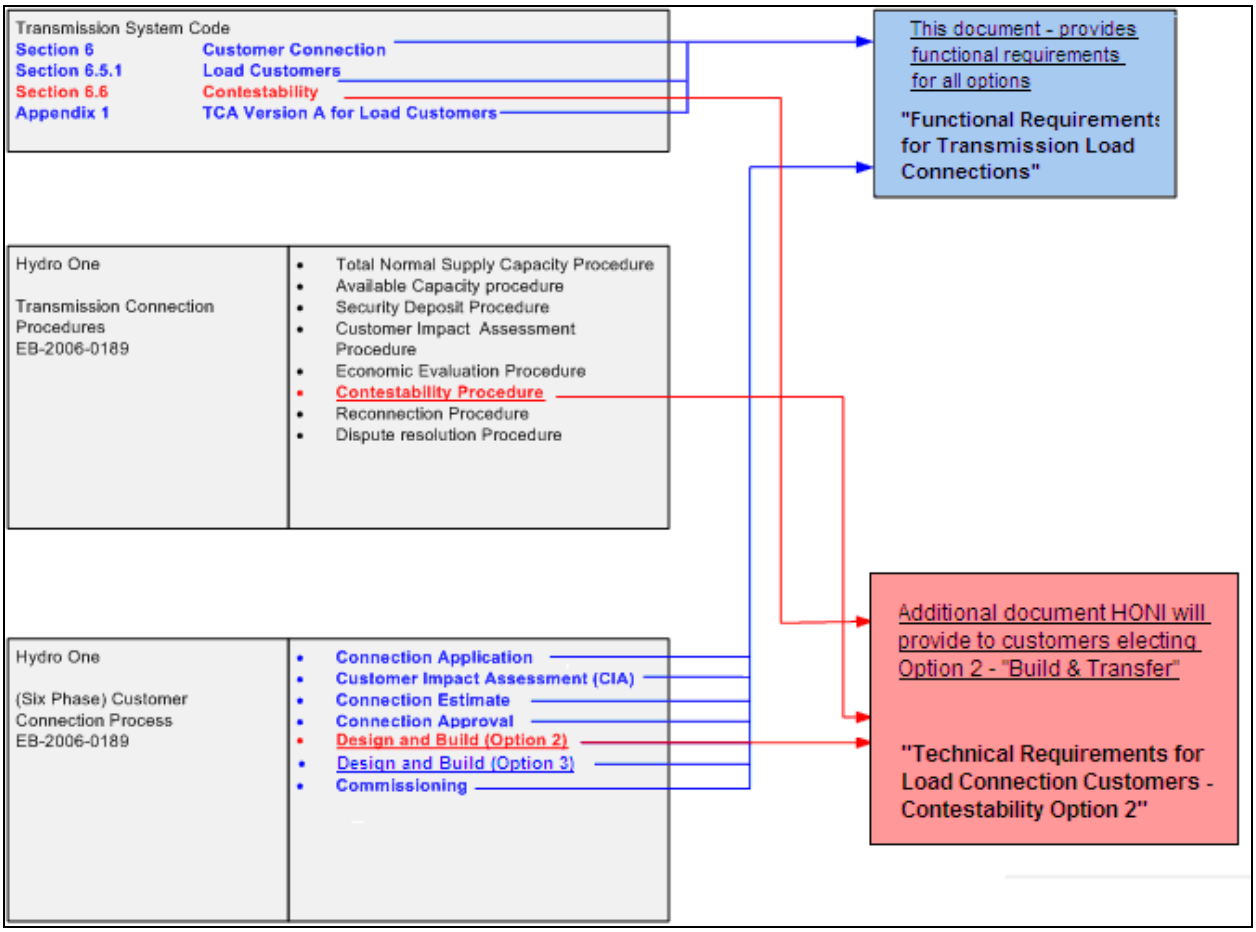

Figure 1 – Relationship between various codes and documents

Note: Customers should initiate the IESO's Application and Approval Process simultaneously with initiating Hydro One's Customer Connection Process as the two processes run parallel.

2.0 DEFINITIONS

All definitions used in the Transmission System Code (including the TCA attached thereto) will apply to these Functional Requirements for New Transmission Load Connections. In addition, all references to technical equipment, processes and schemes will be as per accepted industry standard.

For the purpose of this document, an emergency situation is defined as one in which human life, property or system stability is at risk.

"LCS" means Load Connection Station

"TSC" means the Transmission System Code issued by the Ontario Energy Board on July 25, 2005, as updated from time to time.

"TCA" means Transmission Connection Agreement

"CCRA" means Capital Cost Recovery Agreement

"COVER" means Hydro One's Confirmation of Verification Evidence Report

"DESN" means Dual Element Spot Network configuration of a step-down transformer station

3.0 APPLICATION AND INTERPRETATION

Section 3.0 (Applications and Interpretation) of the TSC applies to this document.

4.0 STANDARDS

4.1 GENERAL REQUIREMENTS

In addition to the general requirements set out in Section 4.1 of the TSC, the following requirements apply:

R4.1.1 Hydro One shall provide load customers with any necessary information that is in Hydro One's possession, or reasonably available, in order to comply with its obligations under the TSC.

R4.1.2 All transmission LCSs shall conform to all applicable government, safety, regulatory, and industry related requirements, practices and standards unless noted otherwise.

R4.1.3 All transmission LCSs owned by customers with embedded generation connected to those stations shall ensure that those facilities conform to the applicable sections of the TSC and all government, safety, regulatory, and industry related requirements, practices and standards unless noted otherwise.

R4.1.4 All connections to the transmission system shall be made with due regard for the safety of Hydro One's employees, the customer's employees and the public.

R4.1.5 New connection facilities shall not in any way materially reduce the reliability or performance of Hydro One's existing transmission facilities or cause a material negative impact on any other customer connected to the transmission system (including, but not limited to existing customers' power quality).

R4.1.6 Customers who propose to make any changes after the commissioning of a customer owned substation that may impact the performance or operations of the interconnection protections[1], whether a setting change, design change, equipment change or other changes, must communicate that proposed change to Hydro One and that change must be reviewed by Hydro One prior to the change taking effect. Where necessary, as determined by Hydro One, such change will be incorporated into the customer's TCA.

4.2 TRANSMISSION SERVICE CHARGES

Not applicable for the purpose of these Functional Requirements. See Sections 22 and 23 of the TCA for customer obligations.

4.3 FACILITIES STANDARDS AND REQUIREMENTS

In addition to the provisions under Section 4.3 of the TSC and the requirements set out in Sections 24, 25 and 28 as well as Schedules E, F and G of the TCA, the following requirements apply.

The load customer must ensure that the load connection facility:

R4.3.1 Is designed and constructed in compliance with the Market Rules and the reliability standards of all applicable standards authorities (NERC, NPCC) that have not been stayed or revoked by the OEB according to its authority (Electricity Act 1998); and

R4.3.2 Conforms to Hydro One's OEB approved connection procedures EB-2006-0189.

The load customer must ensure that the data of customer procured transformers, lines etc., required for the planning, design and operation of connections, and for the Customer Impact Assessment (CIA) study and System Impact Assessment (SIA) study are complete and accurate and provided to Hydro One and as applicable to the IESO. In some cases, testing may be required to establish modelling data at the customer's cost.

R4.3.3 The load customer must allow Hydro One to witness the commissioning and testing under the provisions and terms of the TSC (ex. TSC 4.3.3) at the discretion of Hydro One.

Additional project specific requirements may also be applicable.

[1] Interconnection protections, or interface protections, are those protections that cover, protect, or influence the connection of the load connection to the Hydro One system.

4.4 OPERATIONAL STANDARDS AND REPORTING PROTOCOL

See Section 26 of the TCA for customer obligations.

4.5 PERFORMANCE STANDARDS

Not applicable for the purpose of these Functional Requirements.

4.6 COMPLIANCE OF FACILIITES WITH STANDARDS

The facilities shall comply with the applicable standards as described in Section 4.3 of this document.

4.7 CONFIDENTIALITY

Hydro One includes confidentiality provisions in all study agreements and CCRAs that it executes that are consistent with Section 4.7 of the TSC. For customers pursuing Option 2, Hydro One will require that a separate confidentiality agreement be executed before it releases Hydro One's technical specifications for load connection facilities to be transferred to Hydro One.

5.0 REQUIREMENTS FOR OPERATIONS AND MAINTENANCE

See Section 27 of the TCA for customer obligations.

6.0 CONNECTION PROCEDURES

Sections 6.1.10 through and including Section 6.1.14 of the TSC apply for the purpose of these Functional Requirements.

6.1 HYDRO ONE TRANSMISSION CONNECTION PROCEDURES

In accordance with Sections 6.1.3 and 6.1.4 of the TSC, Hydro One's Connection Procedures (available at: http://www.hydroonenetworks.com/en/customers/connection_process/load/downloads/Transmission_Customer_Connection_Procedures.pdf) have received the approval of the OEB [EB-2006-0189]. The specific procedures approved by the OEB include: Total Normal Supply Capacity, Available Capacity, Security Deposit, Customer Impact Assessment (CIA), Economic Evaluation, Contestability, Reconnection and Dispute Resolution.

6.2 HYDRO ONE TRANSMISSION CONNECTION PROCESS

Hydro One has also produced guidelines on the six stage process for application and connection to the Transmission Grid (available at: http://www.hydroonenetworks.com/en/customers/connection_process/load/downloads/Hydro_One_Customer_Connection_Process.pdf).

7.0 COMPLIANCE, INSPECTION, TESTING AND MONITORING

Please see Section 10 of these Functional Requirements for New Transmission Load Connections for requirements with respect to maintenance, testing and commissioning of protection, control, and telecommunications equipment.

The requirements for compliance, inspection, testing and monitoring of customer equipment are set out in Section 28 of the TCA.

8.0 GENERAL TECHNICAL REQUIREMENTS

8.1 GUIDELINES OF RELIABILITY ORGANIZATIONS

The provisions under Section 8.1 of the TSC apply for this section.

8.2 PROTECTION AND CONTROL

8.2.1 General

In addition to the provisions of Section 8.2 of the TSC the following requirements apply:

Refer to TSC Section 8.2.1a, 8.2.1b, 8.2.1c, and 8.2.1d, Schedule E 1.3.1.1

(a) All LCSs

R8.2.1.1 All LCSs shall be designed with redundant protection systems, unless otherwise accepted by Hydro One. All protection design practices shall be followed, with due consideration to:

(i) Sensitivity
(ii) Speed
(iii) Selectivity
(iv) Security
(v) Dependability
(vi) Maintainability

R8.2.1.2 Each system shall be capable of detecting and clearing faults within their own zone of protection. Overlapping protection zones must be employed to ensure that all power system elements are protected. Each protection system shall be designed with different components, where possible, in order to prevent single contingency failures (common mode failures).

R8.2.1.3 Dual breaker trip coils shall be used on all breakers 230 kV and higher.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.1.1 Hydro One shall specify the conceptual design and equipment to be used.

H8.2.1.2 Failure of one component shall still allow complete tripping of the protected element by the remaining (redundant) system.

H8.2.1.3 Removing one primary protection system from service shall leave a second fully operational redundant or backup protection system in-service.

8.2.2 Instrument transformers

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Sections 8.2.1j, 10.6.1, 10.6.3, 10.6.4, and 10.6.5, Schedule G 1.6

(a) All LCSs

R8.2.2.1 A detailed record shall be provided to Hydro One of all nameplate data for all current and voltage transformers. This includes, but is not limited to manufacturer, date of manufacture, ratios, BIL, physical dimensions, accuracy class(es), thermal ratings, temperature ratings, and voltage/current ratings.

R8.2.2.2 Potential supplies from PTs or CCVTs shall be individually fused.

R8.2.2.3 PTs and CCVTs shall have factory installed ferroresonance circuitry.

R8.2.2.4 Each potential device shall have a minimum of two secondaries.

R8.2.2.5 Each substation shall have either one or three HV PTs. Where the application warrants one PT, then consideration must be given to standard 30 degree phase shift and transformer impedance must be considered when using LV PTs for line protection.

R8.2.2.6 Minimum CT ratios for primary protection equipment shall be rated at 10L400 (C400) on the LV side of the transformer and 10L800 (C800) on the HV side of the transformer.

R8.2.2.7 Current transformers shall be designed with a continuous current rating of 125% of the maximum expected circuit loading.

R8.2.2.8 CTs shall not saturate for worse case faults with full DC offset.

R8.2.2.9 Unused CT outputs shall be shorted at the CT or at the earliest possible point thereafter, and grounded.

R8.2.2.10 A minimum of three CT cores are required on each bushing and phase of each transformer, bus tie breaker, and transformer secondary breaker.

R8.2.2.11 Either wire wound current transformers, optical current transformers or Rogowski coils can be used.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.2.1 All potential transformers (wire wound PTs, capacitive CVTs, or optical voltage transformers) used for transmission load connection protection purposes shall be approved by Hydro One.

H8.2.2.2 All specified nameplate ratios shall have fully distributed windings about the iron core.

H8.2.2.3 Potential transformer and current transformer secondary circuits shall be grounded in one location only (at the first point of termination within the relay building).

H8.2.2.4 Ground connections shall be easily opened, or removable, for maintenance and testing, if required.

H8.2.2.5 The use of either wire wound current transformers, optical current transformers or Rogowski shall be subject to Hydro One's approval.

8.2.3 Protection Zones

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Sections 8.2.1, 10.6.2, Schedule G – 1.6.2

R8.2.3.1 Protection zones (transformer and line, transformer and bus, bus and feeder, etc.) shall overlap in order to ensure that no part of the transmission load connection is left vulnerable to fault conditions without being adequately protected. Where overlapping zones are not possible, these shall be approved by Hydro One prior to construction of transmission load connections.

R8.2.3.2 Either redundant protections or primary and backup protections are required, as appropriate.

8.2.4 Breaker Failure

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Sections 8.2.1 a, 10.5.1, 10.5.2, 10.5.3, 10.5.4, 10.5.5, 10.5.6

R8.2.4.1 All LCSs shall have breaker failure protection on any HVI, transformer secondary breaker and secondary bus tie breaker. Breaker failure protections do not need to be duplicated.

R8.2.4.2 Under no circumstances for any station shall automatic ground switches be used for triggering line protection operation following a failure of a HVI.

8.2.5 Reclosing and synchronizing

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Section Schedule F 1.1.6

R8.2.5.1 Protection and control equipment shall not reclose a live source onto a dead Hydro One connection, that is, no possible back-feed condition into the Hydro One system shall exist or be possible under any circumstances without the express consent and approval by Hydro One.

R8.2.5.2 Reclosing coordination shall be mutually agreed upon, by Hydro One and the customer before any reclosing scheme is put into service. Synchronizing equipment may be required at the discretion of Hydro One.

8.2.6 Utility Grade Equipment

In addition to the requirements in TSC sections listed below, the following additional requirements apply:

Refer to TSC Section 8.2.1g, 10.7.1, 10.4.1 Schedule G 1.4.1

Utility grade equipment must be employed for the protection of transmission load connection equipment. The relays, telecommunication equipment, and any PC/Windows type computer must meet the following (minimum) requirements where applicable:

(a) All LCSs

R8.2.6.1 Shall be substation hardened to meet or exceed ANSI/IEEE standards for protective relaying and telecommunication equipment such as C37.90, C37.90.1, C37.90.2, C37.90.3 and P1613.

R8.2.6.2 PC/Windows type computers shall be DC powered from the station battery.

R8.2.6.3 Output control contacts (or electronic contacts) shall be rated as per the following (minimum) requirements.

(a) Make
1. 30 A
2. Carry 6 A continuous
3. 1 s rating of 50A

(b) Break
1. 48 V, 0.5 A L/R = 40 ms
2. 125 V, 0.3 A, L/R = 40 ms
3. 250 V, 0.2 A, L/R = 40 ms

(c) MOV Protection (if present) 250 V ac and 330 V dc

R8.2.6.4 Contacts that are used for tripping breaker trip coils directly shall be rated according to trip coil characteristics.

R8.2.6.5 Relevant documentation (owner's manual, technical manuals, operational manuals, etc.) shall be provided by the manufacturer and be readily available for operating, maintenance, testing, and troubleshooting purposes. The documentation must correspond with the model of the equipment being described in the documents as well as the firmware being used in the equipment. In some cases technical notes or amendments from the manufacturer that supplements existing documentation may be acceptable.

R8.2.6.6 Protection equipment shall provide minimum trip, alarm, and event recording capability. The records and oscillography shall be time synchronized with a GPS clock.

R8.2.6.7 All protection equipment shall be powered by station battery (DC) supply, typically 125 VDC with shielded supplies.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.6.1 The documentation provided to Hydro One in item R8.25 above shall include equipment specifications and technical data.

H8.2.6.2 Protection equipment shall have manually re-settable trip target indication.

H8.2.6.3 Protection equipment shall provide isolation of input quantities and output trip signals via ABB Flexi Test (FT-1) or comparable isolating switches.

H8.2.6.4 Protection equipment shall be capable of synchronizing their internal clock to a GPS signal (refer to 8.2.7 of this document).

H8.2.6.5 Protection equipment shall have DC supply monitoring alarm annunciation (DC monitoring).

H8.2.6.6 The use of microprocessor-based protection equipment (Intelligent Electronic Devices, IED) for primary protection equipment shall be required, providing for self-testing, event recording, time stamping, and remote access capabilities.

H8.2.6.7 All relays used on transmission load connection equipment shall be approved by Hydro One.

H8.2.6.8 Protection equipment shall be designed for a minimum expected life of 25 years, an expected minimum MTBF of 100 years and a minimum availability of 99.99%.

H8.2.6.9 DC supplies and supply voltage (typically 125 VDC) shall be as specified by Hydro One.

H8.2.6.10 The following shall be approved by Hydro One:

(a) DC control and AC voltage and current wires and cable types;
(b) All terminal block types, fuses and fuse holders;
(c) All relays types and models used in the stations;
(d) All telecommunication schemes;
(e) All telecommunication equipment, including media (fiber, microwave, power line carrier, radio, etc.);
(f) All instrument transformers (current and voltage) including, but not limited to, all ratings, number and type of windings, burdens, location, etc.

H8.2.6.11 All protection schemes characteristics shall be provided by Hydro One and any discrepancies in implementation must be approved by Hydro One prior to design of the substation.

H8.2.6.12 Telecommunication equipment shall have a reliability that is consistent with that of protection equipment.

H8.2.6.13 Hydro One approved methods for terminating cables with appropriate grounding shall be used for all cables.

H8.2.6.14 Any supporting equipment such as interface cables from protection or control equipment and software used for accessing protection and control equipment (such as setting software) must be surrendered to Hydro One upon the transfer of the station to Hydro One as well as any associated passwords.

8.2.7 Battery Banks

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Sections 10.7.1, 10.7.2, 10.7.3, 10.7.4, Schedule G – 1.7.1

(a) All LCSs

R8.2.7.1 Battery systems shall be capable of restoring a depleted battery to full charge within 24 hours.

R8.2.7.2 Battery sizing shall be rated according to IEEE 485-1997 and consider the maximum demands for equipment dependent on battery source voltage.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.7.1 Duplicate supplies (trunks/breakers) with an automatic transfer scheme shall be used for key loads unless otherwise agreed by Hydro One. Duplicate supplies imply two circuits, not necessarily two batteries.

H8.2.7.2 Battery sizing calculations shall be clearly detailed and provided to Hydro One. This information is to be provided to Hydro One during the design stage prior to construction.

H8.2.7.3 After the battery has been installed and prior to operation of the station, proof of discharge testing shall be provided to Hydro One to verify that the battery has sufficient capability to support load and trips as per IEEE 450-2002.

8.2.8 Station Satellite Clock

This section provides further requirements not specifically identified in the TSC.

R8.2.8.1 Protection, control, and SCADA equipment located at transmission load connection facilities shall be connected to a functioning GPS clock so that event records and operational information is accurately time stamped using Eastern Standard Time (EST). Any exceptions must be agreed by Hydro One.

R8.2.8.2 Satellite synchronized clocks are required at all substations with under frequency load shedding.

8.2.9 Special Protections

This section provides further requirements not specifically identified in the TSC.

R8.2.9.1 From time-to-time it may be necessary to implement Special Protection Schemes, also known as Remedial Action Schemes for the purpose of safety, system stability or system security. These schemes may be mandated by the IESO (Market Rules Chapter 4 Grid Connection Requirements, Appendix 4.3, September 2006), or by system requirements as determined by Hydro One.

8.2.10 Contact Personnel

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Appendix 1, Section 27

R8.2.10.1 The customer shall appoint one or more qualified persons to act as a point of contact for protection and control related issues. This person shall have adequate training and experience about protection, control and SCADA.

R8.2.10.2 The names and telephone numbers of the contact person(s) shall be recorded in Schedule A of the TCA. In addition, the customer shall contact Hydro One under any condition(s) in which the protection system might be compromised, or if the protection system has operated.

8.2.11 Safety Requirements

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Appendix 1, Sections 27.10.1, Schedule E 1.7.1.1 and 1.7.1.3

(a) All LCSs

R8.2.11.1 Any protection and control equipment installed in a transmission load connection site shall adhere to current safety guidelines as outlined by the Electrical Code and ESA requirements.

R8.2.11.2 Interconnected protection equipment shall seek to reduce the severity of arc flash by means including but not limited to settings, bus protection, or fast bus tripping schemes[2].

R8.2.11.3 Upon request by Hydro One, the customer shall provide details and evidence of the calculations to indicate the use of specific protection equipment, and/or settings, to minimize the severity of arc flash hazard.

R8.2.11.4 Hazardous working conditions shall be corrected for Hydro One personnel to have safe access to Hydro One owned equipment during inspections, testing, or calibration.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

[2] IEEE 1584-2000 presents various methods for calculating arc flash energies and arc flash protection. Various industry documents present methods for minimizing arc flash hazards by the judicious use of protection settings and coordination.

H8.2.11.1 Power system equipment shall be designed and constructed such that appropriate work protection can be taken out on such equipment in order to isolate it from the power system, with the goal that work on protection, control, and telecommunications equipment can be carried out in a safe manner.

H8.2.11.2 Specific requirements for Personal Protective Equipment (PPE) which are currently required by Hydro One for safe work practices in a substation environment shall be clearly stated for all equipment.

8.2.12 Information Provided By Hydro One

H8.2.12.1 Listed below is some of the basic power system information that Hydro One may provide to customers in order to design a transmission load connection. All information that is required shall be discussed with Hydro One prior to the customer entering into any contractual agreements with third parties.

(a) Available utility short-circuit current and associated X/R ratio
(b) Expected minimum, maximum, and nominal voltage levels
(c) Outage history of the supply
(d) Estimated frequency, duration, and magnitude of momentary voltage dips
(e) Operating requirements and constraints
(f) Requirements necessary to coordinate protections with the utility system
(g) Harmonic content, voltage fluctuation, and current unbalance limits imposed by the utility
(h) Load shedding requirements
(i) Temporary overvoltages due to faults or load rejection
(j) Voltage unbalance

Additional information may be provided as per specific discussions.

8.2.13 Information Provided by the Customer

R8.2.13.1 Listed below is some typical information that may be required by Hydro One for protection and control assessment:

(a) Expected in-service date
(b) Complete one-line and three-line diagrams of the connection system
(c) Supply voltage
(d) Transformer ratings, connections, voltage taps, and impedances
(e) Power factor correction capacitor ratings and connections
(f) Available short-circuit current
(g) Switchgear specifications
(h) Protective relay types and ranges
(i) Protection and control schematic drawings and settings, as appropriate
(j) Protection philosophy and tripping matrix.
(k) Motor loads, types, sizes, starting current, contactor data, and frequency of starts
(l) Unusual load characteristics

(m) Generator and large synchronous motor information, including ratings, impedance data, time constants, and exciter data
(n) Expansion plans, which include projected loads, future substation development, and estimated dates
(o) Method used to ground neutrals and ratings of the neutral grounding device
(p) All main and auxiliary current transformer ratios, taps, and accuracy class
(q) All main and auxiliary potential transformer ratios, taps, and accuracy class
(r) Interrupting time of all HVI, transformer secondary and bus tie breakers
(s) Calculated and measured station ground resistance
(t) Voltage and KVAR rating of capacitors
(u) Voltage and KVAR rating of reactors

Additional information may be required as per specific needs.

8.2.14 Documentation Requirements

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Section Schedule G 1.3.7, 1.3.8

(a) All LCSs

R8.2.14.1 Written documentation shall be required that outlines compliance with NERC, NPCC, and IESO regulating agency requirements, if required.

R8.2.14.2 Documentation shall be provided to Hydro One both in printed copy form and permanent electronic form using up-to-date media such as DVDs (i.e., floppy disks, or memory sticks will not be accepted). Electronic documentation must be in a common format such as Word 2003 or 2007. Documentation, if compressed, must use commonly used compression technology such as “zip” and must not be password protected, unless otherwise specified by Hydro One.

R8.2.14.3 Drawings shall be supplied via printed and electronic copies. Printed and electronic copies shall comply with Hydro One’s drawing design specifications and electronic copies shall be in AutoCAD format. A master transmittal list showing all documents and revisions numbers and dates shall be submitted with the package to Hydro One. Any changes made to prints, documentation, schematics, etc., shall be documented and included in the final version submitted to Hydro One.

R8.2.14.4 Documentation pertaining to the interface protection, control and telecommunications equipment shall be submitted to Hydro One. The interface equipment is defined as any equipment that covers, protects or influences the interface of the load connection to the Hydro One system.

R8.2.14.5 Hydro One may at its discretion require additional documentation.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.14.1 Two copies of all documentation associated with protection and control related equipment shall be provided to Hydro One prior to ownership transfer. This applies to manufacturer documentation, commissioning procedures and results, maintenance procedures, purchasing specifications, design documentation, schematic diagrams (including EWD, CWD), calibration reports, and manufacturer change notices.

H8.2.14.2 All drawings and reports shall be prepared and stamped by a Professional Engineer.

H8.2.14.3 The documentation supplied to Hydro One shall include but not be limited to the following:

(a) All protection AC & DC EWDs & CWDs
(b) All breakers control AC & DC EWDs & CWDs
(c) All SCADA AC & DC EWDs & CWDs
(d) Teleprotection schemes AC & DC EWDs and CWDs
(e) Special protections AC & DC EWDs and CWDs
(f) All relay logic diagrams
(g) All relay settings & supporting calculation documents as required
(h) Panel Layout (Electrical Arrangement EA)
(i) Floor plans
(j) Switchyard schematic one line diagram
(k) Switchyard phasing diagram
(l) AC & DC station service diagrams
(m) Single line and three line diagrams
(n) All P&C equipment labeling information
(o) Cable list
(p) Protection description
(q) Equipment documents

8.2.15 Nomenclature Requirements

(a) All LCSs

R8.2.15.1 Protection nomenclature used for all drawings, documentation, and correspondence, shall be as defined in the latest version of IEEE C37.2 and supplemented by any Hydro One specific requirements.

R8.2.15.2 Drawing symbols shall be as per IEEE 315.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.15.1 All panels, cables, protection devices (primary or auxiliary relays), switches, current links, fuses, auxiliary CTs or PTs, target indicators, control switches, DC circuit breakers, communication channels, and mimic panels shall be labeled according to their functionality based on the electrical Wiring Diagram (EWD) identification or Connection Wiring Diagram (CWD) identification.

H8.2.15.2 Labeling shall be verified during commissioning.

H8.2.15.3 Cables shall be labeled at both ends.

8.2.16 Sparing Requirements

For substations to be owned by Hydro One the following applies:

H8.2.16.1 No critical equipment shall be used in any Hydro One site without a proper sparing analysis. Critical equipment includes, but is not limited to instrument transformers, primary relay equipment (IEDs) and communication equipment.

H8.2.16.2 Sparing analysis shall be conducted with the purpose of determining if spares are available, what typical lead times will be to obtain spares, how many spares should be kept in inventory, and what is the anticipated life of this equipment with respect to manufacturer support, etc.

H8.2.16.3 Under no circumstance shall obsolete or “used” equipment be used in the construction of any LCS.

H8.2.16.4 All sparing analysis shall be approved by Hydro One prior to construction in order to avoid the use of unacceptable components.

H8.2.16.5 An inventory of recommended spare parts for all protection and control-related equipment shall be provided to Hydro One.

8.2.17 Firmware Requirements

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Section 8.2.1g

(a) All LCSs

R8.2.17.1 Protection equipment firmware used in microprocessor-based devices shall be maintained in a reasonable fashion. It is highly recommended that the process defined in IEEE C37.231 be implemented for maintaining firmware integrity in customer owned substations.

R8.2.17.2 Protection equipment used to interface with Hydro One shall be maintained with up-to-date firmware releases. Any critical firmware release must be implemented and notice of such implementation passed on to Hydro One.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.17.1 Protection equipment used in substations must have up-to-date Hydro One standard firmware installed. Any deviation from this practice shall be communicated to Hydro One 30 days prior to commissioning the station. Hydro One shall approve any deviations on a case by case basis.

8.2.18 Cyber Security

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

Refer to TSC Appendix 1, Sections 27.13.1 and 27.13.3, NERC CIP-001-1

(a) All LCSs

R8.2.18.1 For substations or load centers deemed to be critical to the operation of the Ontario power grid, any modem connections, wireless connections, fiber connections, or any other connection by which data or information can be transmitted to or from the substation shall conform to current cyber security standards (CIP) as adopted by NERC.

R8.2.18.2 Non critical substation owners can implement these security requirements at their discretion.

R8.2.18.3 The owner of any transmission connection facility deemed to be critical, shall cooperate in all matters of security related to the operation of the transmission system. As part of the NERC standards, compliance is monitored and it is expected that transmission connection owners shall cooperate in Hydro One initiatives to verify compliance with NERC CIP requirements.

R8.2.18.4 Under no condition shall manufacturer default passwords be used for any protection device. Passwords must be changed on a routine basis at least once per year.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.2.18.1 All passwords used for electronic devices shall be surrendered to Hydro One upon completion of commissioning.

H8.2.18.2 A detailed list of the equipment, location, and serial number for each device shall be associated with the appropriate password in order to ensure that every password is accounted for.

H8.2.18.3 For devices that have multiple levels of security, each and every password shall be provided to Hydro One. This applies to all electronic relays, modems, SCADA, and any other device that may use password protection.

H8.2.18.4 Contact personnel from the customer may be subject to a background security clearance check at the discretion of Hydro One.

8.3 INSULATION COORDINATION

In addition to the provisions under Section 8.3 of the TSC, the following requirements apply.

(a) All LCSs

R8.3.1 The insulation coordination (i.e. the correlation of the insulation of electrical equipment and circuits with the characteristics of protective devices) for the load connection station (LCS) shall withstand a variety of overvoltages of different magnitudes, shapes and durations[3].

R8.3.2 Insulation Co-ordination Study incorporating the LCS Basic Surge Levels, surge arrester protective characteristics, surge generation and transfer, conductor spacing, co-ordination between station and transmission line, and shielding from lightning, shall be documented and submitted to Hydro One.

R8.3.3 For connection to the Transmission System, Hydro One shall provide nominal operating voltages and maximum system operating voltages.

R8.3.4 Devices connected to the transmission system shall be specified with LIL/BIL levels consistent with normal and maximum operating voltages. The intent is that such devices will enable a connected installation to withstand switching surges and lightning surges consistent with all other facilities forming the transmission system.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.3.1 The preferred system for protecting against lighting involves the installation of an optimized arrangement of lightning protection masts to provide the necessary degree of shielding to the station. The term “mast” is used for a structure or spike without provision for stringing any conductor (skywire).

[3] The wave-shape of the overvoltages is important in determining the withstand capability of the insulation system. The voltages to which the insulation system is exposed include, and are not limited to the normal 60Hz voltage, temporary overvoltages, slow front (switching) surges and fast front (lightning) surges.

H8.3.2 The shielding system shall be designed to provide a Mean Time between Shielding Failure of minimum 500 years, per LCS area.

H8.3.3 The standard approach to surge protection is to provide suitably rated metal oxide, station class surge arresters at major components and systems, such as power transformers, shunt capacitors and at underground cable interfaces. Rod or pipe gap surge protective devices are not acceptable.

H8.3.4 Minimum Striking Distances in Air (Metal-to-Metal) will be provided by Hydro One.

H8.3.5 Project specific requirements for insulation coordination of major equipment shall be provided by Hydro One. Additional project specific requirements may also be applicable.

Refer also to Section 14.1.2 (Safety by Design) for stations.

8.4 GROUNDING

In addition to the provisions under Section 8.4 of the TSC, the following requirements apply.

(a) All LCSs

R8.4.1 The load connection facility's grounding system shall meet ESA requirements on a "stand alone" basis, and shall not rely on Hydro One's grounding system in any way.

R8.4.2 The grounding systems shall be designed and installed to ensure safety of personnel and equipment in and around the transformer station. Grounding systems shall provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems shall limit the damage to equipment during faults or surges and ensure proper operation of protective devices such as relays and surge arresters.

R8.4.3 Station grounding systems shall be connected to any of Hydro One's grounding system(s), only after:

(i) Hydro One reviews the customer's ground potential rise ("GPR") study (produced at customer's cost by a Professional Engineer registered in Canada, or professional engineer with credentials recognized by the PEO – (Professional Engineers Ontario) as required in the TSC, and determines that such grounding system is adequate on a "stand alone" basis.

(ii) The customer provides to Hydro One a written certification from ESA's Professional Engineer registered in Canada or PEO recognized credentials that the customer facilities including their grounding system meets ESA requirements on a "stand alone" basis.

Please refer to the Canadian Electrical Code (Sections 10 and 36) and IEEE Guide for Safety in AC Station Grounding (IEEE Standard 80) on the requirements for the design of these systems to maintain safe levels of step and touch potentials.

R8.4.4 The grounding installation shall be capable of carrying the ultimate maximum ground fault current for the specific station fault magnitude and duration, as specified in the Table of Ratings, without causing any hazardous potentials, potential gradients, interference to other systems, or damage.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.4.1 The load connection facilities shall include but not be limited to permanent grounding systems, as well as temporary bonding and grounding system to ensure staff to safely work on de-energized equipment:

H8.4.2 Permanent grounding systems in LCS station shall be designed to 40 kA fault level

H8.4.3 All above grade metallic facilities shall be securely bonded to the grid with grounding conductors.

H8.4.4 Additional ground rods shall be securely bonded to the grid at major facilities and particularly at surge arrester locations.

H8.4.5 Telephone service using metallic pair cable shall be isolated from ground to avoid damage by the high voltage spikes that are observed in ground grids during faults.

H8.4.6 All transmission line structures within the station shall be adequately bonded and grounded to the ground grid to control step and touch potentials and to provide adequate lightning performance.

Additional project specific requirements may also be applicable.

8.5 TELEMETRY AND MONITORING

In addition to the requirements in the sections of the TSC listed below, the following additional requirements apply:

8.5.1 Real-time data to be provided by the customer

Refer to TSC Appendix 1, Schedule E, Section 1.6 and Schedule I

Under the TSC, owners of transformer stations connected to Hydro One's transmission facilities, have an obligation to provide real time data, pertaining to their equipment**.**

These requirements for real time operating information apply to all customer-owned load-supplying transformer stations connected to Hydro One's HV facilities. The quantities and

device statuses, defined below, shall be monitored and transmitted continually to Hydro One. Such details are to be captured in Schedule I of the Customer's TCA, as required by Hydro One and the TSC.

R8.5.1.1 The following information is required:

A) Analogue Quantities

(a) Where HV voltages are monitored
  (I) HV active power (MW) and reactive power (MVAR) flows and directions for each transformer
  (II) Three phase to phase or three phase to neutral voltages of each HV winding or bus

(b) Where HV voltages are not monitored
  (I) Low voltage active power (MW) and reactive power (MVAR) flows and directions for each transformer winding or for each LV bus
  (II) Three phase to phase voltages of each low voltage bus

(c) Under load tap changer (ULTC) positions

(d) Off load tap changer (OLTC) positions do not have to be telemetered. However, the customer must provide Hydro One with the in service OLTC positions and notify Hydro One of any changes thereafter.

B) Device Statuses

(a) All HV circuit breakers/switchers and bus tie breakers
(b) All HV line-disconnect switches
(c) All HV bus/tie sectionalizing switches
(d) All LV transformer and bus tie breakers and switches
(e) All LV capacitor breakers or isolating switches

For stations operated by Hydro One, the following information is also required:

(a) Three phase feeders currents
(b) Status of all feeder breakers
(c) Status of all feeder-breaker reclosing (armed or not armed)
(d) Status of all feeder-tie switches
(e) Other site specific data

C) Alarms

An alarm signal shall be generated and transmitted whenever a customer owned protection, which is designed to trip Hydro One's breakers, operates. A separate alarm must be provided for each circuit supplying the customer. The alarms shall

identify the name of the transformer station and the designation of the HV interrupted circuit.

8.5.2 Monitoring Reporting

Refer to TSC Sections Schedule I I.1.3, I.2.6

(a) All LCSs

R8.5.2.1 Any transmission connection substation owner shall comply with requests for sequence of events records (SER) or digital fault records as requested by Hydro One or any controlling authority such as the IESO or NPCC within 30 days of request.

R8.5.2.2 Waveforms and event data supplied to Hydro One shall be in COMTRADE format.

R8.5.2.3 Station owners shall analyze all protection system misoperations in order to take corrective actions to avoid future misoperations.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H8.5.2.1 Substations shall be equipped with digital fault recording functionality.

H8.5.2.2 Digital fault recorders, or IEDs with digital fault recording capability, shall be synchronized to a GPS clock.

8.5.3 Method of Delivery

8.5.3.1 Communication Protocol and Demarcation

(a) All LCSs

Real time operating information shall be provided directly from the station(s) or from the customer's SCADA master, as described below.

R8.5.3.1.1 The required hardware and software shall be provided and arrangements shall be made, as needed, with a commercial provider of communication services to deliver the operating data to the demarcation point.

R8.5.3.1.2 Each party shall be responsible for all costs, initial and ongoing, and maintenance of their equipment and communication circuits up to the demarcation point.

R8.5.3.1.3 From the RTU at the LCS to Hydro One's control centre serial DNP 3.0 protocol shall be used as follows:

(I) to Hydro One's communication hub site and through the gateway to Hydro One's control centre, with the demarcation point being inside Hydro One's hub site

(II) where (I) is not feasible, to a Hydro One HV station and through the RTU or gateway to Hydro One's control centre, with the demarcation point being inside Hydro One's station

(III) where (I) and (II) are not feasible, through a Frame Relay Network of a common carrier to Hydro One's control centre, with the demarcation point being the CO nearest to the customer's station

(IV) where (I), (II) and (III) are not feasible, Hydro One will provide communication circuit options available for a particular site.

(V) where modems will be used in any of the above communication methods, Hydro One shall determine the modem type and requirements considering communication media, site location, reliability, and amount of data transfer.

R8.5.3.1.4 From a SCADA master through a Frame Relay Network to Hydro One's SCADA master using ICCP, the communication demarcation point shall be the CO of a common carrier.

8.5.3.2 Reliability Requirements

R8.5.3.2.1 The delivery of the real time data at the communication demarcation point shall have unplanned failure rates and repair times as described in Table 1 below:

Table 1 – Failure Rates and Repair Times for Real time Data

Failure	Mean Time to Failure	Mean Time to Repair
Failure to delivery data from a single station	4 years	24 hours
Simultaneous failure to deliver data from 2 to 5 stations	5 years	4 hours
Simultaneous failure to deliver data from more than 5 stations	20 years	4 hours

R8.5.3.2.2 Prior to connection to Hydro One facilities, the customer shall submit a reliability evaluation report which demonstrates that the above requirements can be satisfied.

8.5.3.3 Planned Outages

R8.5.3.3.1 The customer shall coordinate any planned interruption to the delivery of real time data with Hydro One.

8.5.3.4 Performance Requirements

R8.5.3.4.1 At the output of the customer's RTU, the operating data delivered to Hydro One shall have:

(a) an overall end-to-end measurement error no greater than 2%;
(b) a delay no greater than 2 seconds from the change in the field of the monitored quantity or status for a simultaneous change of up to 15 monitored points, following a single contingency at or outside the customer's station; and
(c) a skew no greater than 0.5 second

R8.5.3.4.2 Prior to connection to Hydro One facilities, the customer shall submit a report which demonstrates compliance with the above requirements.

8.6 SITE ACCESS

R8.6.1 Site access shall be in accordance with the terms of CCRA executed by the customer and Hydro One.

9.0 TECHNICAL REQUIREMENTS FOR TAPPED TRANSFORMER STATIONS SUPPLYING LOAD

Refer to TSC Section 9.0

For all load connection facilities, the customer must meet all requirements of the TSC Section 9.0 as applicable and other OEB and regulatory requirements.

The following is intended to provide further clarification of requirements as defined in the TSC Section 9.0.

9.1 SUPPLY CONSIDERATIONS

In addition to the requirements in the TSC Section 9.1, additional project specific requirements may also be applicable.

9.2 PROTECTION REQUIREMENTS

In addition to the provisions under Section 9.2 of the TSC, the following requirements apply.

(a) All LCSs

R9.2.1 Transmission load connection equipment shall consist of protection elements as indicated in generalized tables in this section (Tables 3 – 7). These protections are referred to as "interface protections."

R9.2.2 Specific (detailed) requirements for connection protection shall be discussed with Hydro One during the design stage and prior to any work being commenced.

R9.2.3 All settings on transmission load connection equipment shall be reviewed by Hydro One at least 60 days prior to being placed in-service.

R9.2.4 Neither Hydro One nor the customer shall rely on the other's protection scheme to protect their own equipment.

R9.2.5 Hydro One will not be liable for miss-coordination or improper protection of customer owned equipment.

R9.2.6 Hydro One utilizes three-pole tripping exclusively. No exceptions shall be made to this philosophy.

R9.2.7 Equipment, such as line differential protections, communications equipment, transfer trip relaying, etc. shall be compatible with Hydro One owned equipment where applicable such as in line differential schemes and certain communication schemes used for teleprotection.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H9.2.1 Hydro One shall provide the technical requirement details for major equipment (transformers, breakers, arrestors, line connectors, etc.) where required.

9.2.1 Line Backup Protections

(a) All LCSs

R9.2.1.1 Line backup protections are required when transformers are connected to separate supplies (transmission lines) and are connected in parallel on the transformer secondary (Figure 2) or if EMF infeeds exists on the low level bus (Figure 3). For such cases, the line protection shall "see" all line faults and trip at the connection site to remove all connection site fault infeeds.

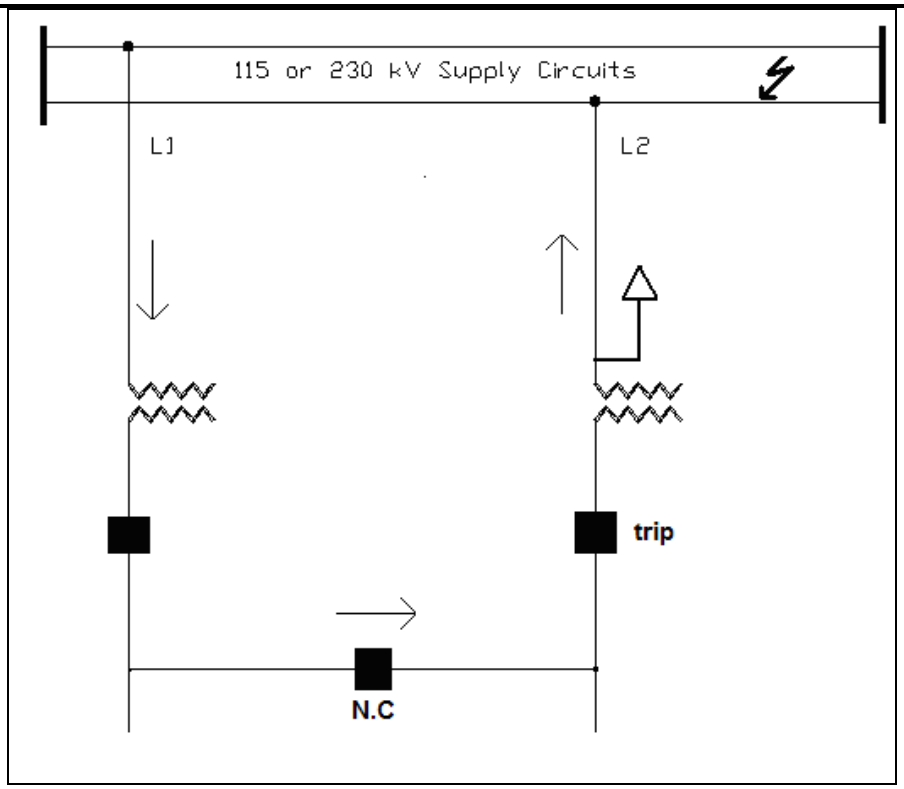

Figure 2 – Line backup protection required – Transformers in parallel

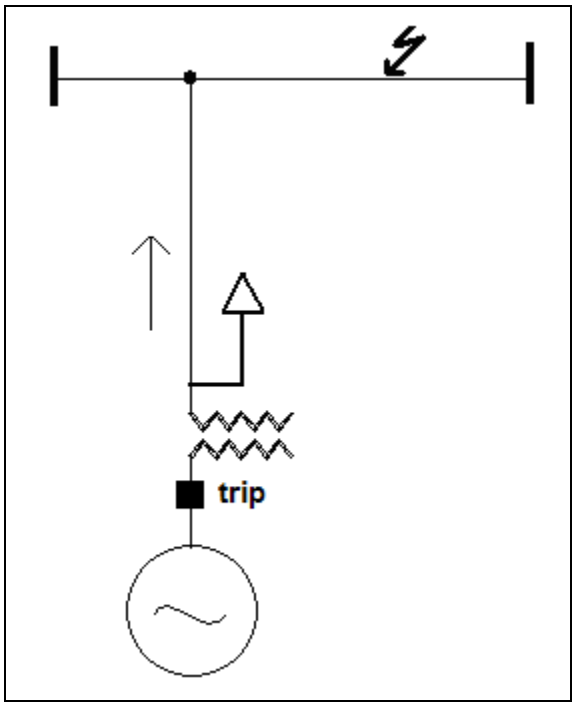

Figure 3 – Line backup protection required – EMF exists on low-voltage bus

9.2.1.1 Line Backup Phase Protection

(a) All LCSs

R9.2.1.1.1 Line phase backup protection shall be implemented either via MHO distance or directional overcurrent elements directioned toward the line away from the station to ensure (a) immunity from operation for station load and (b) operation as a backup to transfer trip from the terminal stations for line faults.

R9.2.1.1.2 These elements require voltage polarization.

R9.2.1.1.3 The voltage polarizing shall either be implemented via a three phase voltage instrument transformer on the HV side of the station or on the LV bus (with voltage transfer).

R9.2.1.1.4 Where the LV bus voltage instrument transformers are used the -30 degree phase shift through the power transformer shall be accounted for where current is measured on the HV side of the transformer.

R9.2.1.1.5 The protection timer shall coordinate with the remote breaker failure protection.

9.2.1.2 Line Backup Ground Protection

Refer to TSC Schedule F 1.2.2.

(a) All LCSs

R9.2.1.2.1 Ground faults shall be protected by means of either $3V_0$ (requires three phase-ground PTs) protection or 27/59 protection where appropriate, or transformer ground (residual) overcurrent protection (50N) if applicable.

R9.2.1.2.2 The 27/59 protection is conditional on the HV neutral grounding of other tapped transformer stations on the same connected transmission lines.

R9.2.1.2.3 Where only one PT on the primary is used, there shall be three PTs on the low voltage (bus) side to provide potentials for the line protection.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H9.2.1.2.1 Where voltage detectors are used, substations shall have three PTs or CVTs on the primary (line side of the transformer).

9.2.2 LV Breaker Failure & Reclose

(a) All LCSs

R9.2.2.1 The low voltage (LV) breakers shall be equipped with a simple breaker failure scheme.

R9.2.2.2 When a protection initiates a breaker failure of the LV breaker and the breaker has not opened (detected by “a” pallet) within 0.3 seconds, all system elements electrically connected to this breaker shall be tripped.

R9.2.2.3 LV breaker failure also shall key transfer trip if no HVI device is present.

R9.2.2.4 A contact of a Test/Normal switch shall be connected in series with the “a” pallet to prevent misoperation during maintenance.

R9.2.2.5 Automatic reclosure of the LV breaker shall be required to restore power to the LV bus following the clearance of a HV fault and the subsequent restoration of the line. With voltage monitoring on both sides of the breaker, reclosure occurs under two conditions:

(i) HV voltage presence, LV undervoltage plus a time delay

(ii) Synchrocheck or HV and LV voltage presence plus time delay

9.2.3 Bus Tie Breaker Failure

This is similar to LV breaker failure but no reclosure is provided and TT is not initiated.

9.2.4 Transformer Protections

For transformers rated 50 MVA or greater:

R9.2.4.1 Two transformer differential protections and gas protection shall be provided. These shall be designated as “A87” and “B87” and “63”, respectively – refer to Figure 4.

R9.2.4.2 Restricted ground fault protection shall be provided for high impedance grounded transformers.

R9.2.4.3 A restricted earth fault protection using the high impedance differential principle is required – refer to Figure 5.

R9.2.4.4 For transformers rated below 50MVA, one transformer differential designated “A87,” and a HV connected overcurrent (51) transformer phase backup protection with 64 ground connected overcurrent for ground fault protection shall be provided – refer to Figure 6.

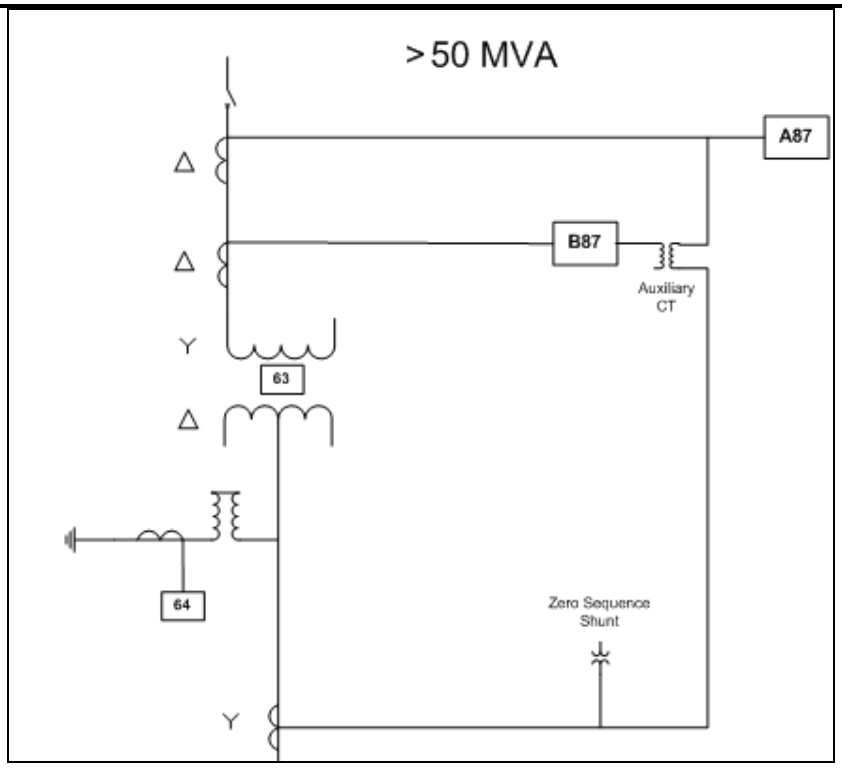

Figure 4 – 64 Ground Connected Overcurrent

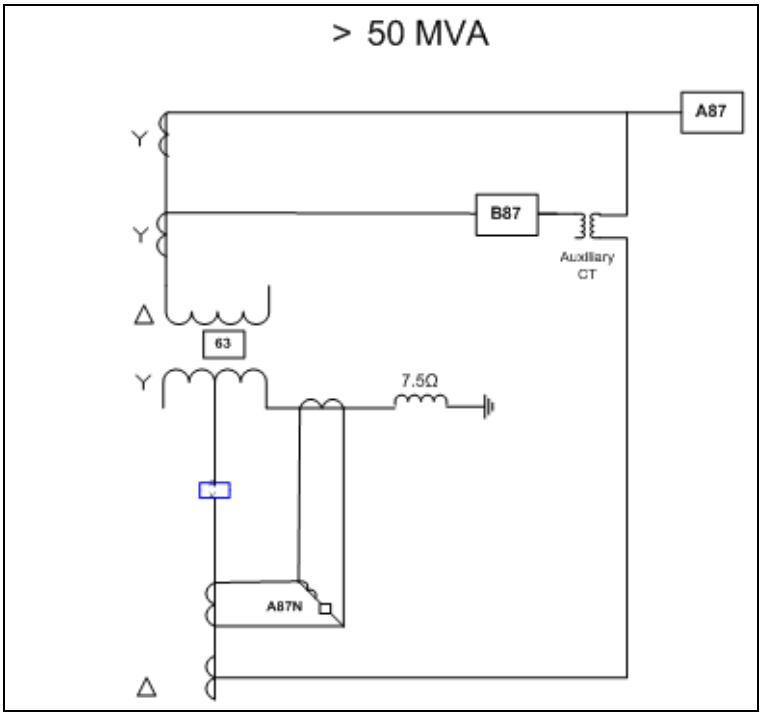

Figure 5 – A87N Transformer Protection

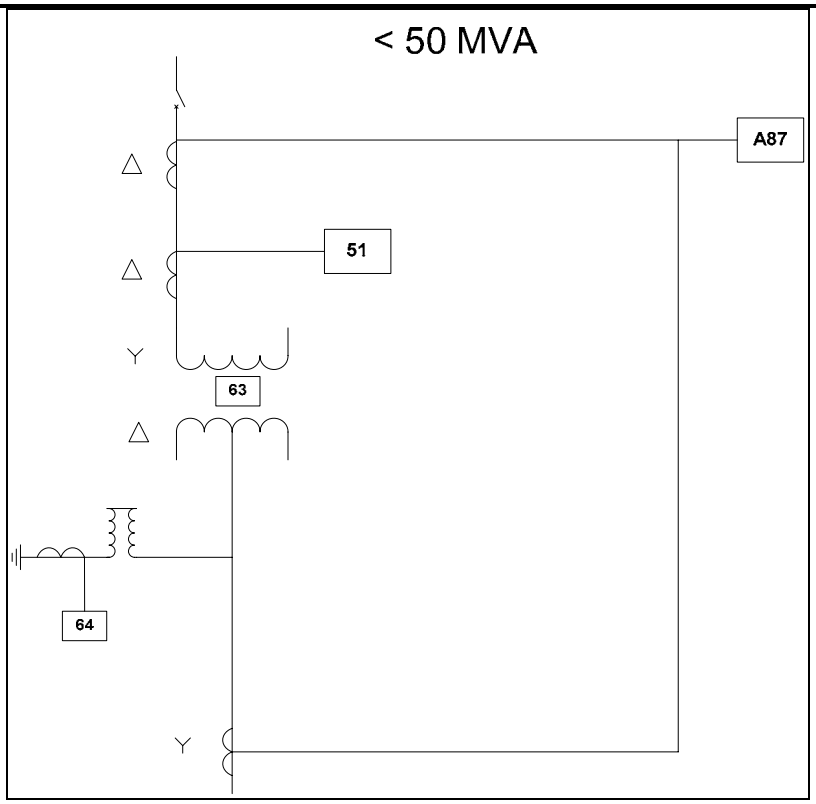

Figure 6 – Transformer 51 Protection

9.2.5 Master Ground Protection (3-wire LV systems)

For stations to be owned by Hydro One the following applies:

R9.2.5.1 Master ground protection shall be provided.

R9.2.5.2 Two master ground relays shall be provided to supervise the ground relays.

R9.2.5.3 The master ground relays shall be connected in parallel with both transformer neutral CTs.

9.2.6 Typical Transformation Configurations

In general there are three scenarios for connecting to the Hydro One system. Requirements on the transformer protection, bus protection and breaker failure protection follow. These three scenarios are discussed below and affect primarily the line protections only.

Scenario A – No High Voltage Interrupting (HVI) Device

In this scenario, the connection to the Hydro One system is by means of a disconnect switch only – no HVI is included in the substation design. Figure 7 shows an example of a DESN station with no HVI, the various protection elements as well as the power system elements.

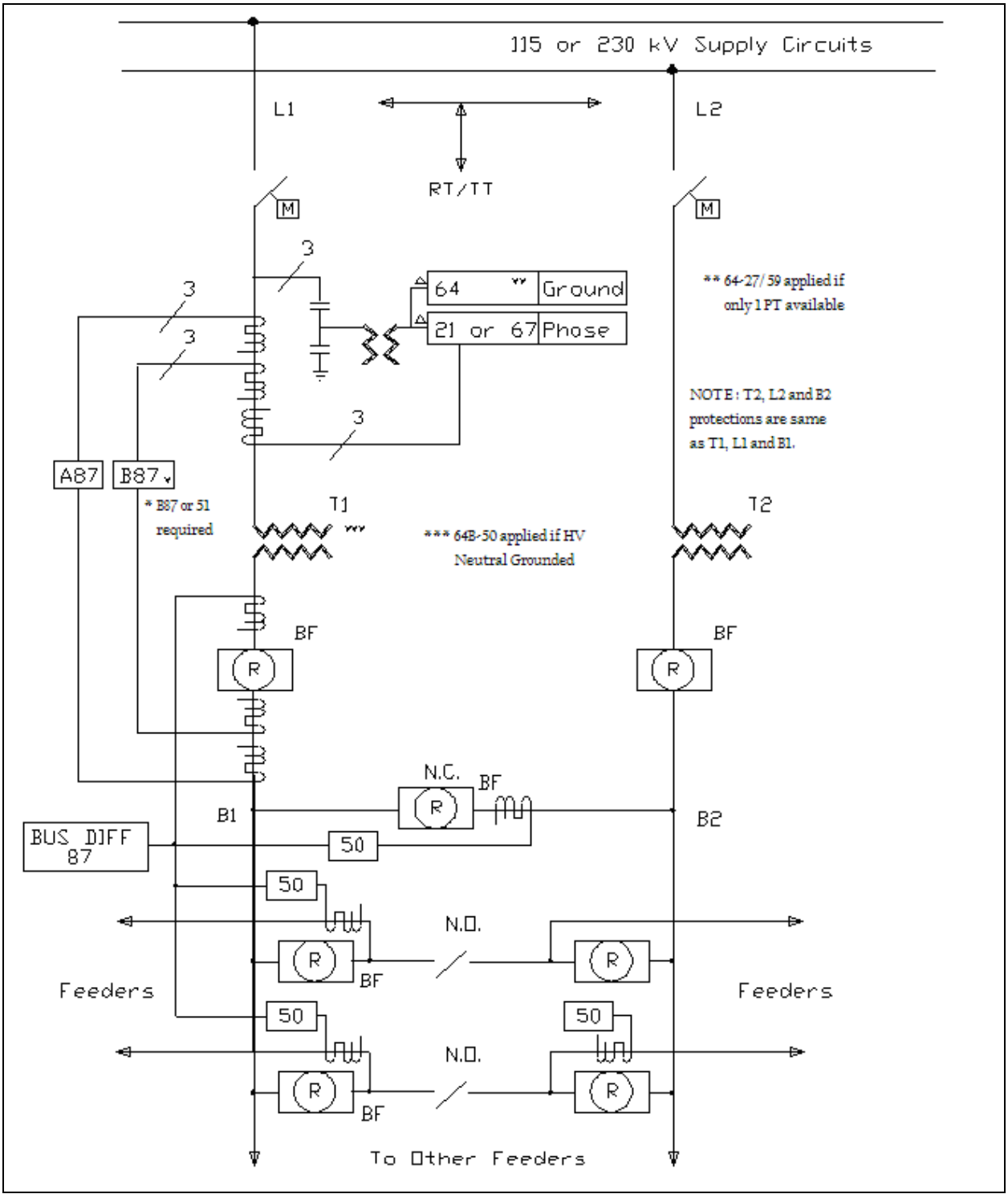

Figure 7 – DESN Station with no HVI

R9.2.6.1 Transfer Trip (TT) is the main protection that sends a trip to the line terminal breakers for Transformer zone faults and BF of the LV breaker, and receives a TT signal from the line terminal protections in order to trip the transformer low voltage breaker(s) at the connection site.

R9.2.6.2 Two TT channels are to be provided for tones on a leased SCED4 line and one channel is required for fiber-based TT. Where there is a single fiber the terminal equipment shall have dual power supplies.

R9.2.6.3 The backup protection shall consist of distance (21) or directional overcurrent (67) for phase faults and residual voltage 3V0 (64) for ground faults.

R9.2.6.4 In cases where a remote trip or transfer trip signal is sent as a result of a transformer fault, the customer (connection) shall open a motor operated disconnect switch to isolate the transformer from the Hydro One System (this shall be done after a suitable time delay).

R9.2.6.5 When the disconnect switch is fully open, RT/TT shall be blocked. RT/TT must be sent for 20sec or until the disconnect is open whichever is later. For RT/TT due to BF, the BF must be sent for 45sec.

R9.2.6.6 Transfer Trip[4] send signals shall be supervised by a pallet switch from the motor operated disconnect switch in cases where two transformer differential protections are used. For such cases, the TT signals shall be supervised by the disconnect switch pallet only when one of the two protections operate. The logic shall be such that if both operate, no supervision is used.

Table 2 – Basic Line Protection Requirements – No HVI

Protection Device	Device Number	Hydro One Owned	Customer Owned
Phase Distance or Directional Overcurrent – A protection	A21 or A67	X	X
Ground Residual Voltage or Over/Under Voltage or non-dir overcurrent	64 or 64-27/59 or 64B-50	X	X
Transfer Trip		X	X

Scenario B – With HVI Device

In this scenario, the connection to the Hydro One system is by means of a disconnect switch and an HVI device. See Figure 8 for an example of a DESN station with an HVI. Figure 8 shows the protection elements as well as the power system elements.

[4] Transfer trip and remote trip generally apply to the same thing; however, remote trip refers to a dc connection between points, whereas a transfer trip refers to some other form of communication media.

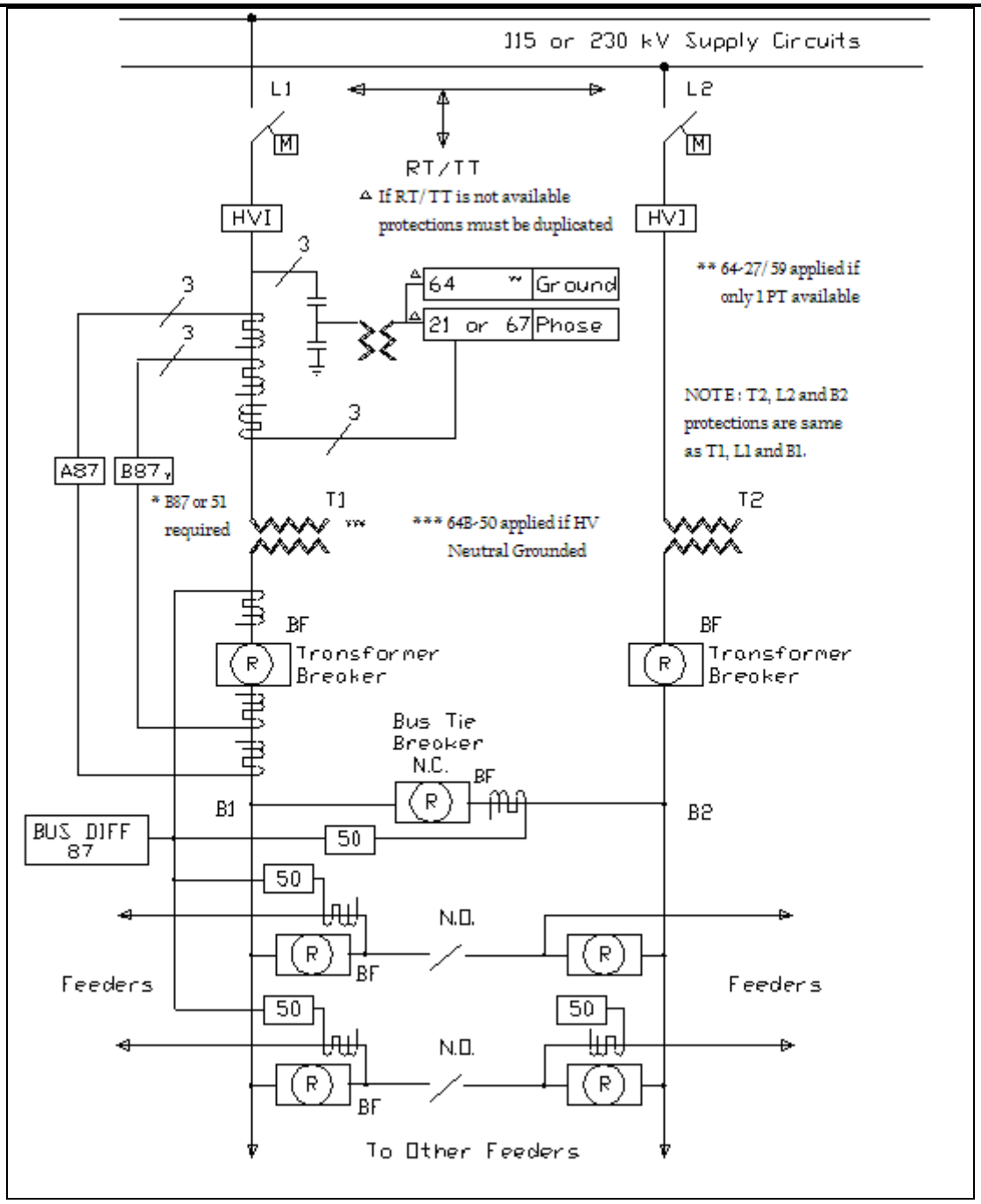

Figure 8 – DESN Station with HVI

(a) All LCSs

R9.2.6.7 A motor operated disconnect switch in series with it on the line side of the HVI shall be provided.

R9.2.6.8 HVI devices shall have trip coil monitoring for all connections.

R9.2.6.9 HVI devices shall have two inputs; one for tripping the interrupter where the two are in one unit (e.g., S&C Circuit Switcher) and one for opening the disconnect switch.

R9.2.6.10 In cases where Transfer Trip capabilities are not required (such as the case when there is an HVI device), dual line protections (A protection and redundant B protection) using either a distance relay or directional overcurrent relay shall be used for phase faults. Ground fault protection requires redundant 27 and 59 or 3Vo (64) or 64B-50, depending upon system parameters and the transformer connection.

Table 3 – Basic Line Protection Requirements – With HVI

Protection Device	Device Number	Hydro One Owned	Customer Owned
Distance or Directional Overcurrent – A protection	A21 or A67	X	X
Ground Residual Voltage or Over/Under Voltage or non-dir overcurrent – A protection	A64 or A64-27/59 or A64B-50	X	X
Distance or Directional Overcurrent – B protection	B21 or B67	X	X
Ground Residual Voltage or Over/Under Voltage or non-dir overcurrent – A protection	B64 or B64-27/59 or B64B-50	X	X

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H9.2.6.1 HVI devices shall have Test/Normal switches in order to remove the HVI control from SCADA operation and place the device in local (Test) control.

Scenario C – HVI Device with LV tie open

This scenario is a slight variant of scenario B with the HVI device. In this case the LV tie breaker is open.

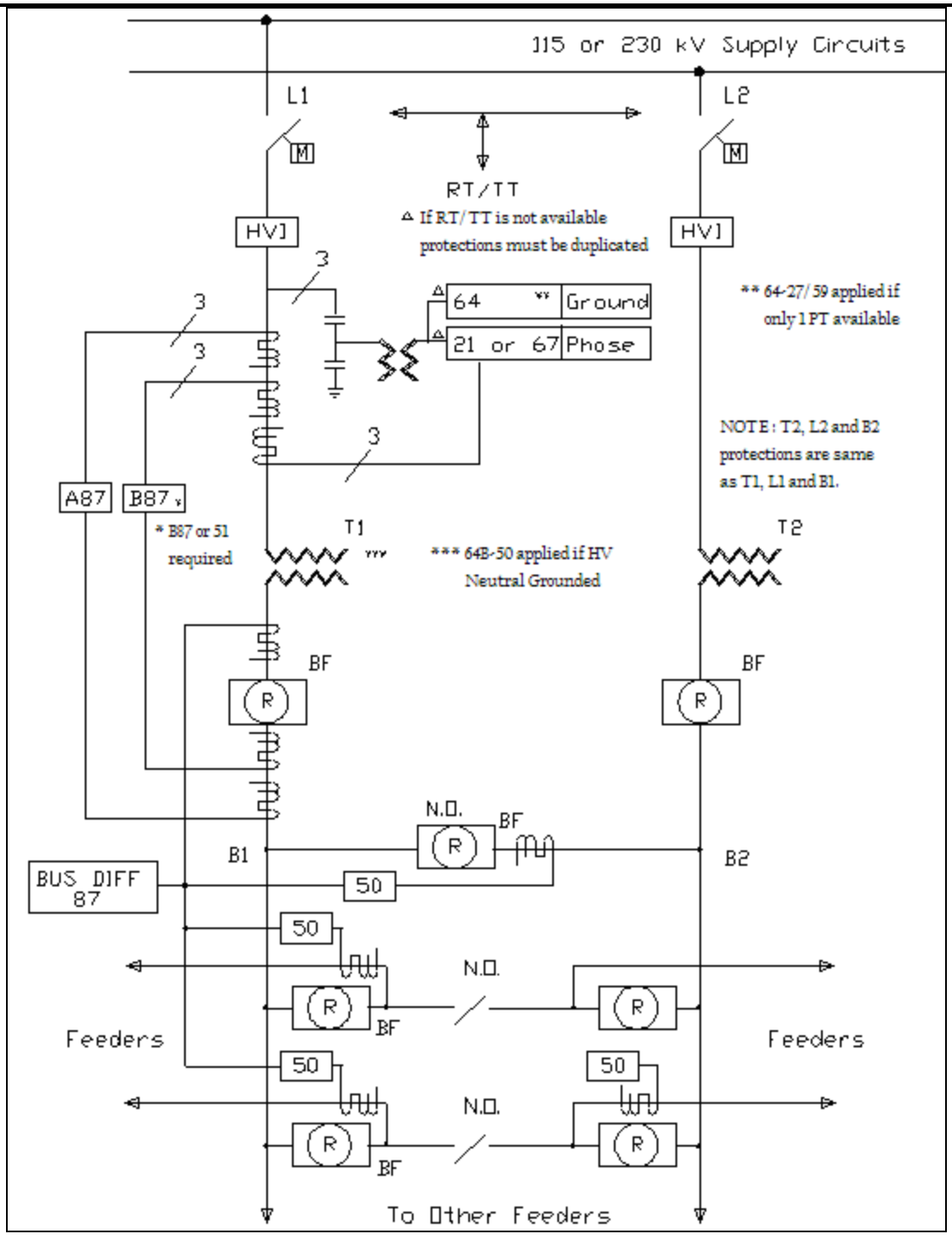

Figure 9 – DESN Station with HVI –Bus Tie Open

Transformer and bus requirements

R9.2.6.11 The transformer and bus protection required shall the same for each of the various configurations (Scenarios A and B). The following Tables list the general protection requirements.

Table 4 – Basic Transformer Protection Requirements

Protection Device	Device Number	Hydro One Owned	Customer Owned
Transformer Differential – A protection	A87	X	X
Transformer Differential – B protection (>50MVA)	B87	X	X
Transformer backup (<50MVA)	51 64		X (or redundant "B" diff)
Ground overvoltage (For primary ungrounded wye or delta transformers)	64-59	X	X
Ground undervoltage (For primary ungrounded wye or delta transformers)	64-27	X	X
Ground directional overcurrent or transformer neutral (For primary grounded wye)	64B-50	X	X
Restricted earth fault if high impedance transformer reactor (neutral) grounded (7.5 ohm) for one group only	A87N	X	X
Master Ground(for low voltage bus with high impedance grounding)	64M	X	X

Table 5 – Basic Bus Protection Requirements

Protection Device	Device Number	Hydro One Owned	Customer Owned
Bus Differential – A protection	87	X	X
Bus Backup – B protection	51B/51NB (ph/gnd)	X	X
Breaker Failure (bus tie, if applicable)	50BF	X	X
Under frequency (Load Shed)	81U	X	X

Table 6 – Basic LV & Bus Tie Breaker Failure Requirements

Protection Device	Device Number	Hydro One Owned	Customer Owned
Breaker Failure	50BF	X	X
Breaker Reclose *	79	X	

* Not provided for bus tie breaker

9.3 TRANSMISSION LINES AND TRANSMISSION LINE TAPS

This Section applies to Transmission Lines and Transmission Line Taps to be owned by Hydro One.

H9.3.1 Any work on an existing Hydro One right-of-way, or existing Hydro One station shall be executed in accordance with the "Hydro One Safety Rules 2004," as amended from time to time.

H9.3.2 Any required modifications to any of Hydro One's existing facilities shall be performed (engineering, procurement, construction, commissioning) by Hydro One in accordance with the terms of the CCRA.

H9.3.3 All facilities shall be constructed and the construction procedures used shall be in accordance with the Environmental Study Report and any requirements assigned in the Environmental Assessment process.

H9.3.4 The basic project requirements for the proposed transmission line shall be specified in the agreement between the customer and Hydro One detailing the Asset Ownership Transfer.

H9.3.5 Unless otherwise specified by Hydro One, relevant standards and procedures shall be followed in the design of clearances, grades of construction, approvals, etc. for overhead systems and the various overhead line components, including the following:

(a) CSA-C22.3 No.1, "Overhead Systems"
(b) CSA-015-90, "Wood Utility Poles and Reinforcing Stubs"
(c) CSA-O80, "Wood Preservation "
(d) CSA-C108.3.1, Limits and Measurements Methods of Electromagnetic Noise from AC Power Systems, 0.15-30 MHz"
(e) CSA-C411.1, "AC Suspension Insulators"
(f) CSA-C411.4, "Composite Suspension Insulators for Transmission Applications"
(g) CSA-C57, "Electric Power Connectors for use in Overhead Line Conductors"
(h) CSA-C83-96, "Communication and Power Line Hardware"
(i) CSA-C49.1, "Round Wire, Concentric Lay, Overhead Electrical Conductors"
(j) CSA-C49.2, "Compact Aluminum Conductors, Steel Reinforced (ACSR)"
(k) CSA-C49.6, "Zinc-Coated Steel Wires for use in Overhead Electrical Conductors"
(l) CSA-G164, " Hot Dip Galvanized of Irregularly Shaped Articles"
(m) CSA-B33.4-1973, "Galvanized Steel Tower Bolts and Nuts"
(n) CSA-W48.1, "Mild Steel Covered Arc-welding Electrodes"
(o) CAN-G40.21, "General Requirements for Rolled or Welded Structural Quality Steel/ Structural Quality Steel"
(p) ANSI/ASCE-10, "Design of Latticed Steel Transmission Structures"
(q) ASCE Manual 72, "Design of Tubular Steel Transmission Structures"
(r) ASTM-A394, "Standard Specification for Zinc-Coated Steel Transmission Tower Bolts"

(s) IEEE Std. 751 Design Guide for Wood Transmission Structures
(t) IEC 61897 Overhead Lines – Requirements and Tests for Stockbridge Type Aeolian Vibration Dampers

H9.3.6 All engineering design calculations and drawings shall be signed and stamped by a Professional Engineer.

H9.3.7 The transmission line route shall be as identified in the Environmental Study Report, Ontario Energy Board Approvals and any commitments made during the "approvals" stage.

H9.3.8 Engineering field survey (plan and profile) of the full length of the line shall be performed. The survey data shall be provided in electronic format that is suitable for the computer software PLS_CADD for structure spotting.

H9.3.9 The right-of-way width shall meet Hydro One requirements to provide appropriate separations between paralleling lines, railways, buildings/structures, or other installations and to meet construction, maintenance, operation, and any environmental requirements.

H9.3.10 All guy wires and anchors shall be located within the right-of-way.

H9.3.11 The environmental conditions used for line design purposes, such as temperature, wind, precipitation, contamination, lightning, etc. shall be based on Environment Canada statistics for the area(s). The design shall include but not be limited to the weather case combinations as stated in the line design. The customer shall adhere to the minimum loading requirements to various line components as specified by Hydro One.

H9.3.12 Minimum safe clearances must be provided between the transmission line conductors and ground, trees, railways, waterways, buildings, other overhead lines and other installations. The line shall be designed and constructed in accordance with the Hydro One's Overhead Line Clearances, as specified by Hydro One. The maximum acceptable conductor temperature for vertical clearance shall not be less than 127^{o} C.

H9.3.13 When in close proximity to, or crossing of, railways, navigable water-ways, pipelines, highways, roads, etc. special clearances or other requirements as established by the owners or governing authorities of those facilities may be required. These clearances or other requirements must be adhered to in the design and construction of the transmission line.

H9.3.14 The conductor size, various conductor design load conditions will be specified by Hydro One to meet the project requirements.

H9.3.15 Overhead ground wire shall be designed to provide lightning protection, line grounding, and to carry the fault current on the line. The ground fault current and fault duration to be used in the design will be specified by Hydro One.

H9.3.16 The line insulation design shall be based on the maximum operating voltage of the line to be specified by Hydro One.

H9.3.17 The line shall be insulated with either ceramic type insulators that meet the requirements of CSA Standards C411.1, or non-ceramic type insulators that meet the requirements of CSA Standard C411.4. The non-ceramic type insulator shall be equipped with appropriate corona ring. The BIL of the insulator strings and the insulator leakage distance requirements shall consider the environmental conditions in the area(s).

H9.3.18 The line hardware shall conform to Hydro One standard hardware arrangements. All hardware shall meet the requirements of CSA Standard C83-96 with steel forged items having the energy absorption level 2. The galvanization of the hardware shall meet the requirements of CSA Standard G164. Hydro One will provide the typical design arrangements for conductor and overhead ground wire suspension and strain (dead-end) assemblies according to the type of structure specified by the customer. All the hardware on the live end shall be corona-free.

H9.3.19 Structure designs shall be steel or wood material of lattice or pole design and shall be approved by Hydro One. All structural steel shall meet the requirements of CSA G40.21-M. The structures shall be designed to be suitable for live line maintenance. The clearances between phases, phases to structures, phases to ground, and phases to ground wire shall be maintained at safe values. Technical design requirements will be specified Hydro One for each specific project.

H9.3.20 Structure foundation shall be designed to meet structure load requirements for soil conditions at the structure locations. Designs are required for firm setting in various soil types including swamp, wet or low bearing soils, rock, muskeg, and must consider scour protection. Under no circumstances shall frozen backfill be used.

H9.3.21 The phasings at the interface points with Hydro One's stations or line facilities shall be specified by Hydro One.

H9.3.22 Hydro One shall provide facilities for connecting the new line. The customer shall identify the location and provide all design requirements of their facilities that interface with Hydro One facilities.

10.0 PROTECTION SYSTEM REQUIREMENTS

Refer to TSC Section 10

The provisions under Section 10 of the TSC apply. Additional project specific requirements may also be applicable.

10.1 TELECOMMUNICATIONS

In addition to the provisions under Section 10.1 of the TSC, the following requirements apply.

R10.1.1 Each transmission load connection facility shall have a working voice communications system in place that is not dependent upon local ac supply and functions reliably. The purpose of this communications is for protection and controls as well as operating personnel use.

10.1.1 Telecommunications requirements

Refer to TSC Sections 10.1, Schedule G - 1.1.1, 1.1.3

The following minimum requirements shall be met for all LCSs:

R10.1.1.1 The telecommunications system shall be dedicated for protection purposes.

R10.1.1.2 All 802.11 wireless communication shall be secured using:

(a) 802.11i or
(b) Public Key Infrastructure (PKI) or
(c) 802.1x device registration

R10.1.1.3 Control systems command and control system data shall be authenticated

10.1.2 Telecommunications Design considerations

The following considerations will be adhered to for teleprotection facilities connected to Hydro One owned equipment where applicable:

R10.1.2.1 The customer facility equipment shall be compatible with Hydro One facility equipment.

R10.1.2.2 The customer shall provide separate A and B battery supply circuits corresponding to A and B protection relays.

R10.1.2.3 Customer shall provide two communication circuits for the transmission of protection commands such that failure of one circuit will not result in the loss of both A and B teleprotections.

R10.1.2.4 Route diversity in communication circuits is encouraged to minimize single point failure and potential of forced power outage to the load.

R10.1.2.5 Hydro One shall suggest communication circuit options available for a particular site.

10.1.3 Telecommunications Protection

R10.1.3.1 Where solid wire connections are used to communicate remote trip or transfer trip signals to the customer, the customer shall install protection equipment to specifically protect against ground protection rise or induced voltages. This protection may take the form of neutralizing transformers and/or gap protection on incoming communication lines.

R10.1.3.2 The customer shall satisfy requirements set by the telephone services provider for installation of telephone cable facilities. These requirements may include but not be limited to GPR (ground potential rise) study, suitable optical isolation equipment, neutralizing transformer, carbon blocks, gas discharge tubes.

10.2 TEST SCHEDULE FOR RELAYING COMMUNICATION CHANNELS

In addition to the provisions under Section 10.2 of the TSC, the following requirements apply.

Refer to TSC Sections 10.2.1, 10.2.2, 10.2.3, Schedule A-A.11.5

R10.2.1 Telecommunications protection equipment between Hydro One and customer sites shall be maintained on a periodic basis.

R10.2.2 Test intervals shall correspond to those used for protection equipment listed in Tables 8 and 9 and the two should be tested simultaneously.

R10.2.3 Channel tests shall be performed according to the following schedule where applicable:

(a) Signal adequacy checks/tests

1. Monitored protection channels at 12 month intervals or by reading the error logs from the equipment
2. Un-Monitored protection channels at 1 month intervals

(b) Channel performance tests

1. Leased services circuits at 24 month intervals
2. Power line carrier at 6 month intervals
3. AM Directional comparison at 12 month intervals
4. Frequency shift PLC at 12 month intervals
5. Frequency shift VF Tones at 24 month intervals

6. Single sideband PLC at 24 month intervals
7. 937 Frequency shift VF tomes at 24 month intervals

10.3 VERIFICATION AND MAINTENANCE PRACTICES / SCHEDULED MAINTENANCE

In addition to the provisions under Section 10.3 of the TSC the following requirements apply. Additional project specific requirements may also be applicable.

10.3.1 Testing and Maintenance Requirements

Refer to TSC Sections 10.3 and 10.4, 8.2.1i, Schedule A.9, Schedule G 1.3, 1.4

(a) All LCSs

R10.3.1.1 Test personnel shall have a clear understanding of the intent of each protection system.

R10.3.1.2 Where applicable, maintenance cycles shall comply with the NPCC Criteria document A-05, “Bulk Power System Protection Criteria.”

R10.3.1.3 UFLS shall be verified on a 4 year cycle provided that staggered cycles are used so that at any time half of the UFLS stations within a district have been re-verified within the last 2 years to comply with NPCC requirements.

R10.3.1.4 Trip testing for UFLS need not be performed more frequently than the trip testing for other Protections on the same breakers.

R10.3.1.5 If the station is not subject to NPCC maintenance criteria, the protections shall be re-verified at the maximum intervals as shown in Table 7.

Table 7 – Applicable for stations not subject to NPCC Maintenance Criteria

	Non-Self Checking Protections	Self Checking[(i)] Protections
Transmission Line Protections	4 years	8 years
Voltage Level 115 kV and above Transformer, Bus, Shunt Reactor and Capacitor Protections	8 years	8 years
DESN bus backup Protections	4 years	6 years
DESN Feeder and L.V. Capacitor Protections	8 years	8 years
All Other [(ii)] Protections	8 years	8 years

The maximum allowable tolerances on calibration or test results are listed in

R10.3.1.6 Table 8.

Table 8 – Maximum Tolerances

Quantity	Maximum Allowable Tolerance
Current	±10 %
Voltage	±10 %
Time	±10 %
Impedance	±0.05 %
Phase Angle	±0.05 %
Frequency	±0.05 Hz

R10.3.1.7 Customers shall provide Hydro One with their commissioning plans.

R10.3.1.8 Hydro One maintains the right to review maintenance, calibration, and operational records for all protective equipment.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H10.3.1.1 Protection schemes shall have test facilities for isolating (and shorting, where necessary) secondary current and voltage signals.

H10.3.1.2 Provision shall be made for monitoring critical relay outputs.

H10.3.1.3 Where communication channels are being utilized, provision shall be made to open or put these channels into a loop-back state.

H10.3.1.4 Transmission load connection protection and control equipment shall be installed such that routine and emergency maintenance can easily be performed. This includes, but is not limited to the following:

(a) Local access to input protection related voltages via FT-1 switches or equivalent
(b) Local access to input protection related currents via current links
(c) Local access to output trip, blocking, or control signal via FT-1 switches, or equivalent
(d) Local access to configuration and diagnostic ports on Electronic Intelligent Devices (IEDs)
(e) Remote indication from protection equipment failure alarms
(f) No protection equipment shall be installed such as to make it permanent and not capable of being removed, or replaced, in the event of equipment failure.

H10.3.1.5 Design and construction shall be so that maintenance can be easily conducted on all equipment.

H10.3.1.6 Specific maintenance plans, in accordance with Hydro One specification shall be provided to Hydro One for review 1 month prior to commissioning.

H10.3.1.7 Maintenance plans shall include, but not be limited to the following:

(a) Location of tests points for each test
(b) All equipment affected by the test
(c) List of required test equipment
(d) Conditions under which the test must be conducted, including outages, test trips, injected qualities, expected outputs (operate levels and timing, for instance) and points to be blocked
(e) Number and qualifications of staff required for each test
(f) Approximate length of each test
(g) Recommended frequency for maintenance
(h) Required supporting documentation (such as manufacturer manuals) and required supporting items (such as special cables or interface software) required to perform any maintenance
(i) Hydro One uses standardized test equipment for protection and control. All maintenance procedures for Hydro One owned equipment shall be developed in order to be compatible with existing tools, techniques, and procedures, as provided by Hydro One

10.3.2 Pre-Energization Inspection

Refer to TSC Appendix 1, Sections 24.5, 24.6, 28.1.1, 28.1.2, 28.1.3, 28.1.4, 28.1.5

(a) All LCSs

R10.3.2.1 The customer shall provide Hydro One a summary of the interconnection protection test results.

(b) Substations to be owned by Hydro One

H10.3.2.1 The customer shall ensure that pre-energization inspection confirms that the station has:

(a) Proper wiring and cabling
(b) Proper wiring and cable terminations
(c) Proper grounding of cables sheaths
(d) Proper grounding of CTs and PTs circuits
(e) Proper fusing of DC buses
(f) Proper access to protection equipment and protection equipment interfaces
(g) Proper security features for cyber intrusion protection
(h) Proper labeling of devices, panels, switches, controls, target indications, communication channels, mimic panels, cables, etc.
(i) Proper practices for wiring, construction, grounding
(j) Proper clearances for access during maintenance
(k) Proper targets, test points, and injection points for maintenance

(l) Check values of resistors external to relays
(m) Proper taps and ratios used on CTs, PTs, auxiliary CTs and PTs
(n) Check that pallets and other interlocking devices are properly connected
(o) "Ring" cables/wires
(p) Verify relay settings

H10.3.2.2 All commissioning documents shall be surrendered to Hydro One upon completion of commissioning procedures.

H10.3.2.3 The customer shall notify Hydro One in advance of any commissioning tests and may at its discretion witness or perform such tests.

H10.3.2.4 Commissioning test shall be conducted by qualified individuals only and all commissioning test reports shall be certified by a Professional Engineer licensed in the Province of Ontario. Evidence of appropriate qualification may be required by Hydro One.

H10.3.2.5 A summary of all protection test results shall be provided to Hydro One.

10.3.3 Commissioning

R10.3.3.1 Once Hydro One agrees with the design/settings, the COVER (Confirmation of Verification Evidence Report) form shall be sent to the customer.

R10.3.3.2 The completed form shall be returned to Hydro One along with the commissioning plans.

R10.3.3.3 Once the commissioning tests have been performed, the customer shall submit the final COVER form to Hydro One along with the commissioning test reports. Refer to the Appendix II.

Commissioning test reports submitted to Hydro One shall include:

R10.3.3.4 Test equipment model and serial number

R10.3.3.5 Information showing adequate test equipment calibration, with reference to a national standard, and date of calibration for all test equipment

R10.3.3.6 The following protection and control related activities and equipment:

(a) CT polarity and ratio tests
(b) CT excitation tests
(c) Phase rotation on PT secondary inputs to relays
(d) Relay commissioning of all protection and control and alarm functions
(e) Relay trip tests, including primary equipment tripping
(f) Verification of all annunciation and SCADA points

(g) Dated with the date that the commissioning procedure was executed and shall be signed with the name of the person responsible for conducting the procedure.

(h) All commissioning reports shall be sealed by a Professional Engineer
(i) Notification of commissioning tests shall be submitted to Hydro One with at least three business days of notice.
(j) All commissioning tests shall be completed at least 7 days prior to the planned in-service date.
(k) Hydro One at its own discretion may waive the witnessing of commissioning tests and may only review the documents.
(l) "As left" setting files must be downloaded (and made available to Hydro One) from each relay as a final record of the settings applied and tested on the protective relaying equipment.

10.3.4 On-Potential and On-Load Checks

Refer to TSC Sections 10.4.2, 10.4.3, Appendix 1 Schedule G Sections 1.4.4 & 1.4.5

R10.3.4.1 The following on-potential checks shall be completed for all transformation substations once the station is energized:

(a) Proper phasing of voltage transformer secondaries applied to relays
(b) Spot check of SCADA readings
(c) Spot check of actual quantities displayed by line protection and transformer protection relays

R10.3.4.2 The following successful on-potential tests, on-load testing shall also be performed in order to verify the following:

(a) Proper phasing of current transformer secondary's applied to relays
(b) Spot check of SCADA readings
(c) Spot check of actual quantities displayed by line protection and transformer protection relays
(d) Detailed reports indicating what on-potential and what on-load testing was performed and the results obtained must be provided to Hydro One for all substations connected to the Hydro One system

10.3.5 Feeders

R10.3.5.1 Provision shall be in place to enable system operators to place a Hold-Off on all feeders.

R10.3.5.2 Instantaneous and timed phase and ground overcurrent relays shall be provided on all radial feeders.

R10.3.5.3 In the case where phase and ground relaying on the bus is not present (for instance, where duplicate bus protections are used), a second form of feeder protection, such as distance, may be required.

10.4 FUNCTIONAL TESTS AND PERIODIC VERIFICATION

In addition to the provisions under Section 10.4 of the TSC, the requirements covered in Section 10.3 of this document apply. Additional project specific requirements may also be applicable.

10.5 FAILURE PROTECTION FOR HIGH-VOLTAGE INTERRUPTING DEVICES (HVIS)

The provisions under Section 10.5 and Appendix I Schedule G Section1.5 of the TSC apply for the purposes of this section. Additional project specific requirements may also be applicable.

10.6 INSTRUMENT TRANSFORMERS

In addition to the provisions under Section 10.6 of the TSC, the following requirements apply. Additional project specific requirements may also be applicable.

Refer to TSC Sections 8.2.1j, 10.6.1, 10.6.3, 10.6.4, and 10.6.5, Schedule G 1.6.3

(a) All LCSs

H10.6.1 A detailed record must be provided to HONI of all nameplate data for all current and voltage transformers. This includes, but is not limited to manufacturer, date of manufacture, ratios, BIL, physical dimensions, accuracy class(es), thermal ratings, temperature ratings, and voltage/current ratings.

10.7 BATTERY SYSTEM AND DIRECT CURRENT SUPPLY

In addition to the provisions under Section 10.7 of the TSC, the following requirements apply. Additional project specific requirements may also be applicable.

Refer to TSC Schedule G section 1.7

R10.7.1 The DC station service shall be a 125 Volt system providing enough ampacity on loss of the battery charger or AC station service to allow the station to operate to comply with the TSC Section 10.7.1.

R10.7.2 Unless otherwise accepted by Hydro One two protected (fused) and monitored DC cabinets are required for load connection stations.

R10.7.3 The DC distribution systems shall utilize moulded-case breakers and fuses in low voltage distribution panels adequately rated for the purpose.

R10.7.4 Separate 125 Vdc circuits shall be provided to each HV breaker and motor operated switch.

Battery

(a) All LCSs

R10.7.5 The batteries shall be sized in accordance with Standard IEEE-485.

(b) Substations to be owned by Hydro One

In addition, for substations to be owned by Hydro One the following applies:

H10.7.1 Batteries shall meet the following specific minimum requirements:

(a) The batteries shall be flooded cell
(b) The batteries shall have a 20 year life rating
(c) The batteries shall be designed and rated for utility and/or switchgear applications
(d) The DC battery shall be connected to the main DC distribution panel without any protective devices in between. Thus the connection distance must be minimized to reduce the possibility of failure.

H10.7.2 The battery charger shall be sized for carrying the continuous load plus eight hour recharge.

H10.7.3 The DC battery voltage levels when out of normal range shall be integrated into an alarm system and be monitored by an operator.

11.0 EMBEDDED GENERATION AND BYPASS COMPENSATION

The provisions under Section 11 of the TSC will apply for this section. Generators are outside the scope of this document.

12.0 DISPUTE RESOLUTION

The provisions under Section 12 of the TSC will apply for this section.

13.0 COMING INTO FORCE

The provisions under Section 13 of the TSC will apply for this section.

14.0 FUNCTIONAL REQUIREMENTS NOT ADDRESSED BY THE TSC – FOR CUSTOMER BUILT AND TRANSFERRED LOAD CONNECTION FACILITIES TO HYDRO ONE

Section 14 provides further requirements not specifically identified in the TSC. The focus is for customers who select Option 2 – customer build and transfer ownership to Hydro One.

System Planning Specifications and more detailed Technical Requirements will be provided as part of the specific project requirements.

14.1 DESCRIPTION OF DESIGN CONCEPTS FOR TRANSFORMER STATIONS

H14.1.1 LCSs shall be designed and built with a life expectancy of 40 years.

H14.1.2 Equipment specification and procurement requirements shall be such to support the requirement above.

14.1.1 Hydro One Load Connection Station (DESN Design)

Figure 7 (Section 9.2.6) depicts a diagram of a typical Hydro One Load Connection Station of the Dual Element Spot Network (DESN) type design.

The arrangement of a DESN station has two supply circuits with one transformer connected to each circuit. The transformers have electrical interruption equipment on the high voltage side and are connected to a common low voltage bus through circuit breakers. Each half of the station and the associated supply circuit is designed to carry the total station load for a limited time period, in an emergency. This arrangement ensures that no load is interrupted during an outage to a transmission line or a transformer. However, a fault on the low voltage bus or bus tie breaker will result in a temporary interruption until load is restored by switching operations.

The Hydro One DESN Transformer Stations embody the concept of reliability of supply by redundancy. The bus tie breaker for the DESN station is normally closed. The design of the HV system shall provide for continuous supply or restoration of supply to the load by switching the LV system for any of the following first contingency conditions:

(a) Outage to a power transformer
(b) Outage to a main bus
(c) Outage to an LV transformer circuit breaker, bus tie circuit breaker, or feeder circuit breaker
(d) Outage to a station service transformer

The design minimizes coincident outages (common mode failure) which would result in an interruption to all or part of the load. In addition, two independent AC station service supplies are provided for DESN TS auxiliaries and connected so that outage to a single element will not result in the loss of station service.

In addition to the standard configuration presented in Figure 7 (Section 9.2.8), other configurations may be considered.

14.1.2 Standardization for DESN Facilities

H14.1.2.1 Stations shall use equipment and parts that meet Hydro One's electrical and physical requirements recognizing that Hydro One retains an inventory of strategic spares to cover emergency replacement of failed major equipment, such as power transformers and circuit breakers.

H14.1.2.2 Requirements such as ratings, limiting dimensions, configurations, accessibility for maintenance and replacement have been standardized to facilitate effective maintainability, including interchangeability.

H14.1.2.3 Hydro One replacement and maintainability requirements, including complete interchangeability of all major components, including but not limited to power transformers, circuit breakers, capacitors and switches, shall be incorporated into the design and construction of the DESN facilities.

H14.1.2.4 Hydro One's normal requirements are for outdoor type stations. However, Hydro One may, at its own discretion, require an indoor station recognizing constraints related to, but not limited to, land, space, and integration into urban settings.

Specific technologies for equipment are used by Hydro One, and information regarding these will be provided as part of specific project requirements.

14.1.3 Transformer Requirements

The power transformers must meet Hydro One requirements.

H14.1.3.1 Hydro One DESN stations have specific transformers sizes and voltage requirements for secondary windings. The transformers sizes are noted in the table below, with the accepted nominal secondary winding voltages for the power transformers.

Table 9 – DESN Stations Transformer sizes

Transformer Size – MVA	No of secondary windings	Nominal Output – kV
45/75	2	13.8
50/83	1	27.6 or 44
60/100	2	13.8
75/125	2 or 1	27.6 or 44 respectively
25/42	1	13.8

H14.1.3.2 In some cases, transformers may require two secondary windings which have different voltages.

H14.1.3.3 Transformer shall be built to meet the physical requirements in terms of footprint, bushing placement, cooler location and other criteria so the unit can be replaced with a system spares unit, or be relocated to another station without unnecessary reconfiguration of other assets.

H14.1.3.4 The Limited Time Ratings (LTR) are provided by Hydro One to permit the second transformer in a DESN station to carry the full load under emergency conditions for a single transformer failure contingency.

H14.1.3.5 Hydro One shall provide the requirement for the transformer winding configuration and grounding. Transformer installations for load customers usually do not have grounded primary winding neutrals due to the impact on system protection.

H14.1.3.6 Load Customer transformers shall be capable of under-load tap changer (ULTC) capability on either the high voltage or low voltage winding, with particulars to be provided by Hydro One.

H14.1.3.7 Outdoor transformer installations shall have heat/fire activated devices to provide an alarm signal to the station control system.

H14.1.3.8 Indoor transformers shall have a fire protection (deluge) system to be triggered by the heat/fire activated devices.

H14.1.3.9 The secondary winding configuration shall be grounded through a reactor or grounding transformer.

H14.1.3.10 Transformers shall be specified to allow for noise control devices such as vibration isolation springs and acoustic enclosures. The use of such noise limiting devices will be subject to application and location and such requirements will be provided by Hydro One.

Additional requirements for transformers will be provided as part of a specific project.

14.1.4 HV Circuit Interrupters/Circuit Breakers Requirements

H14.1.4.1 A high voltage interrupting device (HVI) shall provide clearing of faults on the load customer system and remove electrical system fault infeed currents.

H14.1.4.2 HVIs shall be provided with appropriate back-up protection.

H14.1.4.3 A motor operated disconnect switch shall be provided for electrical isolation to serve as a backup function to the HVI. The function of the disconnect switch is primarily for isolation of electrical equipment, and generally, this equipment is not intended to break load current, except when equipped with specific auxiliary devices.

H14.1.4.4 The HVI shall be a suitably rated circuit breaker, or a circuit switcher as specified

by Hydro One, located at the connection point, unless Hydro One authorizes other devices or locations.

14.1.5 Insulation Coordination and Grounding Requirements

Section 8.3 and 8.4 of this document notes the functional insulation coordination and grounding requirements. Specific project requirements will be provided by Hydro One.

14.1.6 Surge Protection

Surge protection in electrical power systems is implemented in the form of surge arrestors to protect equipment such as power transformers against the effects of overvoltages resulting from lightning, switching surges or other disturbances. LCSs shall meet the following requirements:

H14.1.6.1 Use of station class, gapless, metal oxide surge arrestors to provide the primary overvoltage protection to the power transformers supply side.

H14.1.6.2 Surge arrestors be located as close as possible to the transformer primary bushings.

H14.1.6.3 Use of station class metal oxide arresters on transformer secondary windings, conventional metalclad switchgear, cables, SF6 gas equipment and shunt capacitors, and shunt capacitors to protect against overvoltage.

H14.1.6.4 Surge protection equipment shall be located as close as practical to the equipment being protected, factoring in safety, operability, maintainability and system considerations.

14.1.7 LV Transformer Breakers, Bus Tie-Breaker, and Feeder Breakers

H14.1.7.1 The typical DESN TS concept employs low voltage, outdoor, dead-tank circuit breakers at 27.6 kV or 44 kV.

H14.1.7.2 The circuit breaker interrupting medium may be SF6, or vacuum with integral bushing current transformers, with capability for remote operation, including local trip and maintenance controls and monitoring.

H14.1.7.3 All breaker and current transformer components irrespective of their environment and location in the breaker assembly shall be designed to operate as specified in a temperature range of -40 C to +40 C for outdoor equipment.

H14.1.7.4 Hydro One may accept, at its own discretion, indoor or outdoor metalclad LV switchgear: except at 13.8 kV where only indoor metalclad switchgear is permissible.

H14.1.7.5 Where LV shunt capacitors are installed at a station, only gas insulated or vacuum interrupter circuit breakers shall be used to reduce switching surges. The selection of the technology shall be at the discretion of Hydro One consistent with

meeting the requirements to mitigate the switching surges.

H14.1.7.6 Specific technology will be specified by Hydro One as part of specific project requirements.

14.1.8 Three and Four Wire System

The 44 kV low voltage system is a 3 wire system. The 27.6 kV and 13.8 kV systems are 4-wire systems.

14.1.9 Shunt Capacitors

H14.1.9.1 Hydro One, at its discretion, may require the installation of low voltage shunt capacitor banks on the 13.8 kV, 27.6kV and 44kV systems at the DESN stations.

H14.1.9.2 Capacitor bank ratings range from 10.8 to 32.4 MVAR and they are generally outdoor, rack mounted, apart from some metal-enclosed installations on the 13.8kV and 27.6kV systems.

H14.1.9.3 All capacitor bank configurations shall be double “Y” ungrounded.

H14.1.9.4 Outdoor metal-enclosed type capacitor banks are intended for use on 14.4 kV and 28.8 kV systems only.

Additional requirements, including but not limited to size, configuration, grounding, and weather protection will be provided by Hydro One as part of the specific project requirements.

14.1.10 Circuit Switchers

Circuit switchers, which are mechanical switching devices used for frequent operation for enabling, carrying, breaking electrical current under normal electrical circuit conditions, and also, making, carrying for specified time, and breaking currents under specified abnormal conditions such as electrical short circuits. Unlike circuit breakers, these equipments are not capable of high-speed electrical re-closing. These devices may include an integral isolating device.

Specific technology and specific project requirements will be provide by Hydro One.

14.1.11 Station AC Service

The AC service system provides adequate AC power to meet the needs of the DESN stations auxiliary systems which support the equipment such as transformers (e.g. cooling fans); lighting including outdoor lighting.

H14.1.11.1 LCSs shall provide a 120/208 volt 4 wire system.

H14.1.11.2 A single supply is considered to be adequate for stations having one transformer.

H14.1.11.3 A DESN designed station shall have a dual supply (one from each bus), with an automatic transfer scheme.

H14.1.11.4 Each supply shall be capable of carrying the full station service load.

H14.1.11.5 The station service transformers shall have high voltage fuses to remove a faulted transformer from the bus.

H14.1.11.6 The installation shall meet the requirements of the Ontario Electrical Safety code.

H14.1.11.7 Equipment shall be specified to achieve the required 40 year life expectancy reliability and performance requirements.

H14.1.11.8 Equipment shall meet CSA, ESA and NEMA standards.

14.1.12 Environmental

H14.1.12.1 The customer or its authorized representative shall address all applicable Federal, Provincial, Municipal, Regional and Conservation Authority approvals and compliance with regulations. These shall include and are not limited to any environmental assessment approvals under the Ontario Environmental Act.

H14.1.12.2 The Customer shall ensure that Hydro One does not incur any future environmental or other liabilities during the procurement of site, materials and equipment acquisition and construction of the facility including, but not limited to oil spills, existing soil contamination, sedimentation egress from site during construction, archaeological issues, noise, electrical interference, SF6 gas release to atmosphere or other hazardous material releases to the environment.

H14.1.12.3 Transformers and other equipment shall have oil spill containment. Oil spill containment systems will generally follow the design criteria specified in standard IEEE 980-1994.

H14.1.12.4 Specific project requirements for such system shall be provided by Hydro One.

H14.1.12.5 The Ontario Ministry of the Environment Certificate of Approval for the system may require specific provisions that may affect design, construction and operation of such systems.

14.1.13 Safety by Design

H14.1.13.1 Specific clearances to live electrical buses and equipment shall be incorporated in to the design and construction for worker and public safety and for use of vehicles and work equipment.

Refer to Section 8.3 for strike clearances.

H14.1.13.2 Hard wired telephone systems shall have isolation transformers rated and installed and water pipes from municipal systems shall have isolation links to ensure that the ground potential rise of the station under fault conditions is not transferred to the offsite.

Other specific project requirements will be provided by Hydro One.

14.1.14 Ancillary System Requirements

14.1.14.1 Water and sewage

H14.1.14.1.1 Water and sewage connections to municipal system are generally required at DESN stations. At Hydro One's discretion installation of wells and sewage facilities may be required at rural stations.

14.1.14.2 Drainage

H14.1.14.2.1 A station drainage system shall be required to remove water from the site so that dry, firm subgrades are maintained to support foundations and roadways.

14.1.14.3 Backfill and grading

H14.1.14.3.1 Rough and final grading on the site shall be provided to ensure worker and public step and touch potential safety, erosion control, aesthetics, vehicle use, equipment movement, and minimum maintenance.

H14.1.14.3.2 Crushed stone shall be required for personnel protection against touch and step voltage hazards.

14.1.14.4 Foundations

H14.1.14.4.1 Foundations shall be present for all structural assemblies, transformers, buildings, and other equipment.

H14.1.14.4.2 The foundations shall be designed based on the geotechnical and soil reports.

H14.1.14.4.3 The foundations shall be designed to resist movement from loading, settlement, frost heaving, and overturning moments.

H14.1.14.4.4 The power transformer foundation and the oil containment system shall be designed to permit the installation, operation, and removal of the transformer and its accessories.

14.1.14.5 Structures and Buildings

H14.1.14.5.1 Outdoor steel structures shall be designed and built to support all equipment loads and withstand wind, ice, short circuit and switching stresses imposed on the structures.

H14.1.14.5.2 Constructed on-site and prefabricated buildings are acceptable.

H14.1.14.5.3 Building shall require fire detection and security, fire protection, battery room hydrogen detection, battery ventilation (where applicable), lighting, HVAC systems, and must allow space for operation and maintenance work.

H14.1.14.5.4 All buildings shall be designed to meet the limits and requirements of the relevant building codes and standards.

14.1.14.6 Electrical Hardware

H14.1.14.6.1 Stations shall use electrical hardware and parts that meet industry proven performance, and shall be highly reliable. Such equipment shall be agreed by Hydro One.

14.1.14.7 Oil Containment Systems

H14.1.14.7.1 Transformer oil containment systems shall be provided to ensure that oil within the station remains safely contained on site.

H14.1.14.7.2 The oil containment system can be designed using IEEE 980-1984 standard.

H14.1.14.7.3 The gravity drained oil/water separator design is preferable.

14.1.14.8 Barriers/Fences

H14.1.14.8.1 A suitable fence shall be erected to ensure public safety and site security

H14.1.14.8.2 The type of fence shall depend on such factors as aesthetic considerations and municipal By-Laws.

H14.1.14.8.3 The fence shall meet the minimum requirements of the Electrical Safety Code.

H14.1.14.8.4 The security fences required by Hydro One are normally of chain link construction, a minimum of 2.4 m high and topped with three strands of barbed wire sloping outwards.

H14.1.14.8.5 In those stations where aesthetic requirements are to be met, fences of concrete, masonry or wood construction types will also be considered.

H14.1.14.8.6 Where masonry or other wall type fence is considered, it shall be designed according to applicable building codes.

H14.1.14.8.7 The location of the fence shall take into account public safety, vehicle and personnel accessibility, infringement on private property, environmental requirements, municipal road setback requirements, and natural ground contours.

H14.1.14.8.8 Provision for entry and egress from the station property shall be by suitable gates, of equivalent fence material and construction.

H14.1.14.8.9 The station gate shall be lockable in order to provide controlled access.

14.1.14.9 Station Expansion Including Land

H14.1.14.9.1 All DESN stations shall be designed to allow for expansion based on ultimate planning requirements.

H14.1.14.9.1 Layout arrangements for the complete DESN station shall provide the required bus configurations, adequately rated initial installation, and space and other provisions for future expansion to meet ultimate planning requirements.

H14.1.14.9.2 In the ultimate arrangement of the LV switching area, the circuit breaker positions shall be:

(a)	transformer secondaries:	two or four
(b)	bus tie:	one or two
(c)	feeders:	maximum twelve (or fourteen if shunt capacitor banks are not required)
(d)	shunt capacitors:	maximum two

The specific project requirements will be provided by Hydro One.

14.1.14.10 Air Break Switches

H14.1.14.10.1 Stations shall use electrical hardware and parts that meet industry proven performance, and shall be highly reliable.

H14.1.14.10.2 Equipment shall be reviewed and approved by Hydro One.

H14.1.14.10.3 Air break switches come in various configurations and shall be built to industry IEEE, ANSI and NEMA standards.

H14.1.14.10.4 Hydro One generally uses vertical or double break switches.

14.1.15 DESN and Equipment Performance Requirements

H14.1.15.1 The DESN facilities and related electrical facilities shall meet the requirements of the OEB's TSC requirements in Appendix 2, titled Transmission System Connection Point Performance Standards.

H14.1.15.2 DESN and equipment reliability and maintainability requirements shall be provided by Hydro One.

14.1.16 Animal Deterrent Measures

H14.1.16.1 Reasonable animal deterrent measures shall be provided to all new infrastructure, equipment and control cable raceways and entrance to control buildings.

Additional specific project requirements will be provided by Hydro One.

14.1.17 Cyber Security

H14.1.17.1 The Customer shall ensure that facilities designated as Critical Cyber Assets shall be designed and built to comply with the NERC Standards.

Additional specific project requirements will be provided by Hydro One.

14.2 DOCUMENTATION

H14.2.1 All project related documentation, such as applications & permits; any planning & technical studies (including those identified in TSC Section 6.1.14); engineering documentations including engineering-procurement-construction related specification, drawings, inspection & testing; commissioning reports; instructions, operating and maintenance manuals; shall be provided to Hydro One as part of the transfer of the facilities by the Customer to Hydro One. Listed below are various technical documents that Hydro One expects to receive as a minimum.

H14.2.2 All relevant documents associated with the design, procurement, construction, maintenance, and operation shall be transferred to Hydro One.

H14.2.3 Documentation shall use Hydro One's drawing and documentation naming convention.

H14.2.4 Contractual, legal and financial documents such as the CCRA and land lease and other such types of documents shall be provided.

14.2.1 Applications and permits

These documents include:

(a) Environmental Assessment applications and approvals
(b) Certificate(s) of Approval
(c) (IESO) SIA application and approvals
(d) ESA Application permits
(e) Municipal permits (building, fire etc)

14.2.2 Planning and Studies

Refer to TSC Section 6.1.14

Format for the following studies is not specified, but it is essential that they are signed and stamped by a qualified Professional Engineer

(a) Feasibility studies
(b) Geotechnical studies/reports

(c) Topographical Surveys
(d) Grounding Studies
(e) Insulation Coordination Studies
(f) Lightning studies
(g) Power Factor Studies

14.2.3 Engineering Documentation

H14.2.3.1 All drawings shall be produced following Hydro One's Drawing standards and numbering conventions. Hydro One has an index and numbering convention (TSSI) based on voltage level and discipline.

H14.2.3.2 AutoCAD drawing templates and symbols shall be provided.

H14.2.3.3 Drawings and documentation shall be signed and stamped by a qualified Professional Engineer.

For Stations, the lists of drawings shall include but not be limited to:

1. Site
    a. Basic layout
    b. Site and fencing
    c. Grounding
    d. Station mechanical, drainage
    e. Roads
    f. Lightning protection towers and skywire

2. Station structures and foundations
    a. Footings and containment
    b. TX fire separation walls (if applicable)
    c. Structures
    d. Buildings

3. Electrical Arrangement drawings
    a. Station layout
    b. All outdoor high voltage electrical switchgear, bus structures and facilities
    c. Control cable trenches and ducts

4. Station 1-Line and 3-Line drawings
    a. 1-Line showing all HV equipment and buses, CTs and PTs, protections and telemetry
    b. Engineering and Operating nomenclature
    c. 3-line showing transformer, CT and Pt phasing

5. AC and DC Distribution Elementary Wiring Diagram (EWD) and Connection Wiring Drawing (CWD)

6. All Protection and Control drawings

a. All Elementary Wiring Diagrams and Connection Wiring Diagrams for Protection, Control and Metering Schemes

7. Equipment Lists and Bills of materials

8. Consolidated Cable Lists

For Transmission Lines, the lists of Drawings shall include, but not be limited to:

1. Line survey data, suitable for PLS_CADD structure spotting program

2. Line layout design using PLS_CADD program; including the "backup" files generated by the program

3. Plan and profile data and drawings. Drawings will include conductor profile at maximum sag, structure type, height and adjustment, ruling span, insulator type and rating, design tension of conductor and overhead ground wire under combined ice and wind condition for each line section, etc.

4. Sag and tension calculations including stringing data for conductor and overhead ground wire for each line section

5. Hardware assembly drawings with material lists

6. Insulator technical specifications

7. Structure design, fabrication and erection drawings and design calculations

8. Geotechnical reports

9. Footing drawings and design calculations

10. Guy anchor drawings and design calculations

11. Grounding design data including measured soil resistivity and structure footing resistance at each line structure location

12. Phasing arrangement drawings

13. Vibration damper application data

14. Records of signs and markers installation. Design and drawings of markers as per Clause 5.9.4., if applicable

15. Approved crossing drawings for railway, navigable water-way, highway and pipeline crossings, where applicable (drawings shall include stamp from approving authority)

16. Other “As built” information for the new line including GPS co-ordinates at each line structure location

17. Quality assurance documentation identifying all field checks conducted and results of those checks

Additional specific project requirements will be provided by Hydro One.

14.3 MAINTENANCE CONSIDERATIONS

Refer to TSC Schedule E Section 1.7 & 1.8

H14.3.1 The facilities shall be designed to facilitate routine maintenance without undue interruption to system elements. This requirement should be reviewed as part of the design package.

H14.3.2 All relevant manufacturers’ maintenance requirements and commissioning documentation shall be provided to Hydro One.

H14.3.3 Spare parts provided with the purchase of major station equipment shall also be transferred with the asset including maintenance related components.

APPENDIX I - REFERENCES

1. IEEE C37.2 (1996), 'Standard for Electrical Power System Device Function Numbers and Contact Designations', IEEE Standard.

2. IEEE C37.90 (1989), 'IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus', IEEE Standard.

3. IEEE C39.90.2 (2002), 'IEEE Standard for Withstand Capability of Relay System to Radiated Electromagnetic Interference from Transceivers', IEEE Standard.

4. IEEE C37.90.3 (2001), 'IEEE Standard Electrostatic Discharge Tests for Protective Relays', IEEE Standard.

5. IEEE C37.95 (2002), 'IEEE Guide for Protective Relaying of Utility-Consumer Interconnections', IEEE Standard.

6. IEEE C37.231 (2006), 'IEEE Recommended Practice for Microprocessor-Based Protection Equipment Firmware Control', IEEE Standard.

7. IEEE C57.13 (1993), 'Standard Requirement for Instrument Transformers', IEEE Standard.

8. IEEE 315 (1993), 'Standard Graphic Symbols for Electrical and Electronic Diagrams', IEEE Standard.

9. IEEE 485-1997, 'IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications', IEEE Standard.

10. IEEE 450-2002, 'IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications', IEEE Standard.

11. IEEE 1584 (2002), 'IEEE Standard for Electrical Safety Requirement for Employee Workplaces', IEEE Standard.

12. IEEE P1686 Draft3 (2007), 'Draft Standard for Substation Intelligent Electronic Devices (IED) Cyber Security Standards', IEEE Draft Standard.

13. Ontario Hydro (1977), 'C-5047-77 Specification For Testing Susceptibility of Electronic Equipment to Radiated Interference', Ontario Hydro General Tendering Documents.

14. Ontario Hydro (1989), 'Connection Procedure & Requirements for Customers above 50kV', Ontario Hydro.

15. NERC, Standard PRC-002-1 "Define Regional Disturbance Monitoring and Reporting Requirements".
http://www.nerc.com/page.php?cid=2|20

16. NERC, Standard PRC-005-1 “Transmission and Generation Protection System Maintenance and Testing.” http://www.nerc.com/page.php?cid=2|20

17. NERC, Standard COM-001-1 “Telecommunications.” http://www.nerc.com/page.php?cid=2|20

18. NERC, Standard CIP-001-1 “Sabotage Reporting.” http://www.nerc.com/page.php?cid=2|20

19. NERC, Standard PRC-001-1 “System Protection Coordination.” http://www.nerc.com/page.php?cid=2|20

20. NERC (2006), 'Top 10 Vulnerabilities of Control Systems and Their Associated Mitigations - 2006', http://www.esisac.net/publicdocs/Top_10_vuln_2006_16mar2006_ss.pdf

21. NPCC, Criteria Document A-04”Maintenance Criteria for Bulk Power System Protection.” http://www.npcc.org/viewDoc.aspx?name=A-04.pdf&cat=regStandCriteria

22. IESO (2007), 'Market Rules for the Ontario Electricity Market' http://www.ieso.ca/imoweb/manuals/marketdocs.asp

23. Inshaw, C. & Wilson, R. (2005), 'Arc Flash Hazard Analysis and Mitigation', Presented at the 2005 58th Annual Conference for Protective Relay Engineers, Texas A&M.

24. Buff, J. & Zimmerman, K. (2006), 'Application of Existing Technologies to Reduce Arc-Flash Hazards', Schweitzer Engineering Publication.

Appendix 2

Hydro One proposal for a North Oakville TS

Hydro One Networks Inc.
483 Bay Street
North Tower, 14th Floor
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5970
Fax: (416) 345-5977

March 23, 2009

Dan Steele
Oakville Hydro Electricity Distribution Inc.
P.O. Box 1900
861 Redwood Square
Oakville Ontario L6J 5E3

Subject: Capacity Requirements in Oakville

Dear Mr. Steele:

I am writing in reply to your request for Hydro One to prepare a proposal for a pool-funded TS to serve Oakville Hydro's growth over the 25 year period commencing 2012.

We have prepared the estimate and determined the capital contribution requirements based on the following assumed information. Costs are based on planner's ballpark estimate and include $2M for property, all overheads and interest. The station estimates also factor the on-going equipment failure/ replacement costs; substantial spare parts inventory; end-of-life replacement costs; as well as the cost to operate the station.

In-Service date: May 1, 2012

Capacity of Proposed Station: Option 1 (50/83 MVA DESN) - 102 MW
Option 2 (75/125 MVA DESN) - 153 MW

Total Station Cost: Option 1 - $25M
Option 2 - $29M

Total Line Connection Cost: $1.5M

Based on the foregoing information, the DCF calculations show that the line tap should pay for itself. However, capital contribution requirements for the TS itself are estimated to be $14.6M for a 50/83 MVA station and $18.6M for a 75/125 MVA station.

I trust I have answered your inquiry. Please contact me if you have any questions information.

Yours very truly,

Arthur Fischer
Account Executive
Customer Business Relations