Kenora Hydro
Electric Corporation Ltd.

Public Interest Advocacy Centre
ONE Nicholas Street,
Suite 1204
Ottawa, ON K1N 7B7

March 11, 2011

Attention: Michael Buonaguro

Re: Kenora Hydro Electric Corporation Ltd. – EB-2010-0135

Enclosed please find responses to OEB and VECC supplemental interrogatories, as received by Kenora Hydro March 2, 2011. Copies have been filed through the OEB Portal.

Should you require additional information, please contact me directly.

Yours truly,

David Sinclair
President & CEO
Kenora Hydro
Phone 807-467-2075
Fax 807-467-2068
e-mail dsinclair@kenora.ca

KENORA HYDRO ELECTRIC CORPORATION LTD. (KENORA)
2011 RATE APPLICATION (EB-2010-0135)
VECC INTERROGATORIES – ROUND #2
(Note: Numbering continues from Round #1)

QUESTION #34

Reference: VECC #5 a)

a) Please provide the referenced communication from Hydro One Networks and the Hatch Acres report.

b) As per the original request, please provide the substation reconstruction and refurbishment plan that describes the overall project as initiated in 2006, including scope of work, timetable and anticipated cost.

c) If the documentation requested in part (b) is not available please explain on what basis Kenora's management approved the initiation of the overall project.

d) Please contrast Kenora's current expectation as to the scope of work and cost as compared to that established at the commencement of the project. Please explain any significant variances in cost or timing.

RESPONSE

a) Please see correspondence attached as Appendix A.

b) Please see correspondence and report attached as Appendix A.

c) N/A.

d) The original review prepared in 2006 by Hatch Acres included the installation of a new power transformer, a new gantry to connect the high voltage transmission, new secondary switchgear, associated high voltage switches and arrestors, and work to be done by Hydro One. The work included the redesign to allow for better operability as suggested by Hydro One as shown in 34 (a). The preliminary estimated costs were $1,374,300 which didn't include any ground grid work, refurbishments to remaining transformers, road construction for access, or contingency. It did allow for a new power transformer however.

Upon design completion in 2007, the 5 year capital plan budget totaled $ 3,246,000 which included the original plans from 2006 as well as the refurbishment of T1 and T2 but not T3. T3 was built in 1976 and was to be used as a standby unit in the event of failure of one of the remaining

units. The budget also included the installation of electronic reclosures for meeting IESO under-frequency load shedding requirements.
The lightning strike in late 2007 and subsequent failure of T2 altered the schedule of work, as did the strike by Hydro One Society members, but neither issue changed the overall design. The only difference that resulted was the purchase of a used power transformer to replace T2 instead of the installation of a new transformer as originally proposed. To date, $ 3,090,903 has been spent however the replacement and refurbishment of T1 is scheduled for 2011 at a cost of approximately $ 605,000. This will put the entire project about $ 449,000 over budget from estimates in 2007 for the completion of the remaining work.

The only significant variance was the ground grid compliance. Due to the close proximity to bedrock, it was very difficult to design a system to comply with OESC section 36. Ultimately a core drill was required to expand the existing ground grid outside of our substation facility. To meet code this change exceeded budget by almost $ 200,000.

QUESTION #35

Reference: VECC # 5 b)

a) Are there any OM&A costs forecasted for 2011 that are directly related to expansions to connect renewable generation facilities, and renewable enabling improvements? If so, how much and are they included in the proposed 2011 revenue requirement or will they be recorded in Account 1532?

RESPONSE

a) There are no costs forecasted for 2011 in the OM&A that relate to expansions to connect renewable generation facilities or renewable enable improvements. If any related costs are incurred, they will be recorded into account 1532.

QUESTION #36

Reference: VECC #8 a) – c)

a) Please recalculate the 2011 cost of power (I.e. commodity) based on the following:

- Split establish the overall percentage of 2011 purchased power associated with RPP vs. non-RPP kWh based on the percentages in part c) and the forecast 2011 sales by class.
- Use the following costs from the Board's October 2010 RPP Report (page 3) to value the RPP and non-RPP purchases:
    - RPP - $68.38 / MWh
    - Non-RPP - $65.61 – based on the sum of the forecasted wholesale price and the value of the Global Adjustment.

RESPONSE

a) The following table includes updated cost of commodity assuming the RPP cost of $68.38/M and non-RPP cost of $65.61/M, and the following percentage of customers by class that are on RPP :

- Residential 83.2%
- General Under 50 kW 82.02%
- General Over 50 kW 13.20%
- Streetlights 100%
- Unmetered Scattered Loads 77.43%

Electricity - Commodity	**2011 Forecasted Metered kWhs**	**2011 Loss Factor**			
Class per Load Forecast				**2011**	
Residential	31,773,188	1.0430	33,139,435	$0.06838	$2,266,075
Residential - Non - RPP	6,415,740	1.0430	6,691,617	$0.06561	$439,037
Street Lighting	1,807,975	1.0430	1,885,718	$0.06838	$128,945
GS<50kW	18,339,195	1.0430	19,127,780	$0.06838	$1,307,958
GS<50 kW - Non - RPP	4,020,223	1.0430	4,193,093	$0.06561	$275,109
GS>50kW - RPP	5,985,153	1.0430	6,242,514	$0.06838	$426,863
GS>50kW - Non - RPP	39,356,913	1.0430	41,049,261	$0.06561	$2,693,242
Unmetered Scattered Load	112,026	1.0430	116,844	$0.06838	$7,990
Unmetered Scattered Load - Non - RPP	32,655	1.0430	34,059	$0.06561	$2,235
TOTAL	**107,843,068**		**112,480,320**		**$7,547,453**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	39,831,052	$0.0059	$235,003
Street Lighting		kW	5,737	$1.6355	$9,383
GS<50kW		kWh	23,320,873	$0.0052	$121,269
GS>50kW		kW	116,530	$2.1686	$252,708
Unmetered Scattered Load		kWh	150,902	$0.0052	$785
TOTAL					**$619,147**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	39,831,052	$0.0016	$63,730
Street Lighting		kW	5,737	$0.4187	$2,402
GS<50kW		kWh	23,320,873	$0.0014	$32,649
GS>50kW		kW	116,530	$0.5417	$63,124
Unmetered Scattered Load		kWh	150,902	$0.0014	$211
TOTAL					**$162,117**

Wholesale Market Service					
Class per Load Forecast				**2011**	
Residential			39,831,052	$0.0052	$207,121
Street Lighting			1,885,718	$0.0052	$9,806
GS<50kW			23,320,873	$0.0052	$121,269
GS>50kW			47,291,775	$0.0052	$245,917
Unmetered Scattered Load			150,902	$0.0052	$785
TOTAL			**112,480,320**		**$584,898**

Rural Rate Assistance					
Class per Load Forecast				**2011**	
Residential			39,831,052	$0.0013	$51,780
Street Lighting			1,885,718	$0.0013	$2,451
GS<50kW			23,320,873	$0.0013	$30,317
GS>50kW			47,291,775	$0.0013	$61,479
Unmetered Scattered Load			150,902	$0.0013	$196
TOTAL			**112,480,320**		**$146,224**

	2011	**Allowance for Working Capital**
4705-Power Purchased	$7,547,453	
4708-Charges-WMS	$584,898	
4714-Charges-NW	$619,147	**15%**
4716-Charges-CN	$162,117	
4730-Rural Rate Assistance	$146,224	
TOTAL	**9,059,839**	**1,358,976**

QUESTION #37

Reference: VECC #9

a) If the year-end accruals have been established, please update the response.

RESPONSE

a) The year end accruals have not yet been established, these will be completed by March 28, 2011.

QUESTION #38

Reference: VECC #12

a) Please confirm that the last column in response table was calculated as request in the original question.

b) Please provide the details of the calculation (i.e., the values associated with each of the bullets in the original question).

RESPONSE

a) The following table details the requested information:

b) The following table details the requested information:

Year	Actual Heating Degree Days (A)	Actual Cooling Degree Days (B)	Weather Normal Heating Degree Days (C)	Weather Normal Cooling Degree Days (D)	Difference in Heating Degree Days (F) = (A) - (C)	Difference in Cooling Degree Days (G) = (B) - (D)	Difference in Heating Degree Day apply to Coefficient of **3,808** (GWh) (H) = (F) * **3,808** /1,000,000	Difference in Cooling Degree Day apply to Coefficient of **14,926** (GWh) (I) = (G) ***14,926** /1,000,000	Actual Purchases (GWh) (J)	Estimated Actual Weather Normal (GWh) (K) = (J) - (H) - (I)
2008	6,033	125	5,598	182	434.6	(56.9)	1.7	(0.8)	115.5	114.7
2009	5,739	102	5,598	182	140.5	(79.8)	0.5	(1.2)	113.0	113.6
2010	5,009	170	5,598	182	(589.3)	(11.7)	(2.2)	(0.2)	110.5	112.9

QUESTION #39

Reference: VECC # 13 c) & e)

a) The response provided a revised version of Table 11 as opposed to Table 10, as originally requested. Please provide a revised version of Table 10.

b) Please provide the 2010 year end number of connections for Streetlights and USL comparable to the forecast values provided in Table 10 of the original Application.

RESPONSE

a) In the original application, the underlying calculations of load forecasting and customer growth did include the data back to 2002. Tables 8, 9, and 10 in the exhibits as presented did not show the historical data in question, even though it **was** used it the forecasting model for forecasting kWh and customer counts for 2010 and 2011. There are no changes to the results in Table 10, as there are no changes to the underlying data used for forecasting.

b) Streetlight connections = 532 connections
Unmetered Scattered Loads = 33 connections

QUESTION #40

Reference: i) VECC #14
ii) OEB Staff #15

a) Has and/or does Kenora participate in the OPA's peak saver program?

b) If Kenora has participated in any OPA programs in 2008 and/or 2009 please provide the kW and kWh saved in each year from these programs as reported by the OPA.

c) In response to OEB Staff #15, Kenora indicates there is more than one view as to how the CDM energy targets established by the OEB should be interpreted. Has Kenora approached either the OPA or the OEB to obtain clarification? If yes, please provide copies of any responses received. If not, why not?

RESPONSE

a) Kenora Hydro has not historically participated in the OPA's peak saver program. Kenora Hydro will be participating in the third and fourth quarter 2011 of the Peak Saver program.

b) Information presented as provided by the OPA:

"LOCAL DISTRIBUTION COMPANIES" Tab

OPA Conservation & Demand Management Programs

LDC Statistics

Source: Ontario Energy Board - Reporting and Record Keeping Requirements - Yearbook of Electricity Distributors (*http://www.oeb.gov.on.ca/OEB/Industry/Media+Room/Publications/RRR+Reports/Yearbook+of+Distributors*)

#	Local Distribution Company	Note	2008 Residential Energy Throughput (kWh)	2008 Residential Energy Throughput (%)	2008 Non-Residential Energy Throughput (kWh)	2008 Non-Residential Energy Throughput (%)	2008 Total kWh
39	Kenora Hydro Electric Corporation Ltd.		39,338,336	0.10%	69,225,456	0.09%	108,563,792

2009 Residential Energy Throughput (kWh)	2009 Residential Energy Throughput (%)	2009 Non-Residential Energy Throughput (kWh)	2009 Non-Residential Energy Throughput (%)	2009 Total kWh
39,909,017	0.10%	69,229,284	0.09%	109,138,301

"SUMMARY - LDC" Tab

OPA Conservation & Demand Management Programs

Annual Results at the End-User Level

For: Kenora Hydro Electric Corporation Ltd.

Net Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2008	2009	Total
3	2008 Programs	Final	0.5580	0.0777	0.6358
4	2009 Programs	Final	0.0000	0.5079	0.5079

Net Energy Savings (MWh)

#	Program Year	Results Status	2008	2009	Total
3	2008 Programs	Final	462	423	885
4	2009 Programs	Final	0	389	389

Gross Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2008	2009	Total
3	2008 Programs	Final	0.6177	0.1350	0.7528
4	2009 Programs	Final	0.0000	0.5611	0.5611

Gross Energy Savings (MWh)

#	Program Year	Results Status	2008	2009	Total
3	2008 Programs	Final	862	812	1675
4	2009 Programs	Final	0	640	640

c) There has not been any direction from the OEB as to an **annual** savings target that must be achieved, there is only a **cumulative** MWh saving target which must be achieved by the end of 2014. All utilities understand that the savings as directed by the OEB in our mandated targets are **cumulative**. The various programs that will be introduced throughout our four year program will produce varying kwh savings from year to year, however, the end result of the entire four year program is intended to yield our total mandated savings, regardless of when the savings are achieved.

QUESTION #41

Reference: VECC #15 a)

a) Please restate the 2008-2011 values for account 4405, excluding carrying charges on deferral/variance accounts.

RESPONSE

a) Provided below is account 4405 balance with carrying charges removed:

Account 4405	2008	2009	2010	2011
Total in Account	69,369	39,293	12,125	11,451
Less: Variance Carrying Charges	0	22,768	7,500	7,500
Balance Without Carrying Charges	**69,369**	**16,525**	**4,625**	**3,951**

QUESTION #42

Reference: i) VECC #17
ii) OEB Staff #23

a) Based on the hearing process set out by the Board in Procedural Orders #1 and #2 (i.e., no oral hearing requiring witnesses/travel and no technical conference requiring travel), please update the $150,000 forecasted cost for the current Rate Application.

b) Please indicate the provision included for intervenor costs.

RESPONSE

a) Kenora Hydro estimates the following costs:

Estimated COS Rate Application Regulatory Costs	
Regulatory Cost Category	**Amount**
Total Intervenor Costs - 2011	12,000
OEB Costs for COS Rate Application - 2011	30,000
Consultants Costs for COS Rate Application - 2010	8,787
Consultants Costs for COS Rate Application - 2011	15,000
Total Regulatory Costs to complete Rate Application	**65,787**

This estimated total, amortized over a four year period equals $16,447 per year. The 2011 OM&A expenses will be reduced by $21,053.

QUESTION #43

Reference: VECC #17 c)

a) Please clarify the impact to the response on Kenora's proposed revenue requirement. The revised 2011 charges from the City are $224,110 (gross) and $179,860 (net). Does this mean that the $264.554 2011 charge from the City per the original Application has been revised to $224,110?

RESPONSE

a) This statement is correct. The original amount in the 2011 budget of $264,544 will be revised to $224,110 in the final rate application and the final revenue requirement calculation will be revised to reflect this reduction.

QUESTION #44

Reference: VECC #29

a) Please indicate the USOA account number associated with each of these two accounts.

b) Were any costs recorded in either of these accounts for 2010? If so, how much?

c) Is Kenora forecasting the incurrence of costs associated with Renewable Connections or Smart Grid in 2011 and, if so, have such costs been excluded from the proposed revenue requirement?

RESPONSE

a) Renewable Connections = tracked in balance sheet variance USoA account series 1532.

Smart Grid = tracked in balance sheet variance USoA account series 1535.

b) In 1532, Renewable Connections, there is $9,609.80 in costs and $149.75 in carrying charges.

In 1535, Smart Grid, there are $13.76 of carrying charges.

c) No budget amounts have been made for expenses in these two accounts.

QUESTION #45

Reference: VECC #20 a)

a) Please confirm that for 2011 rates Kenora is proposing to include in rate base smart meter capital deployed as of December 31, 2009.

b) Please explain why the depreciation ($500) associated with smart meter additions in 2011 is included in the revenue requirement and not recorded a smart meter deferral/variance account.

c) Does the 2011 proposed revenue requirement include deprecation for smart meters capital deployed in 2010? If so how much and why?

d) Please confirm that the rate base proposed for 2011 does not include any capital deployed for smart meters in 2010 or 2011. If it does, please indicate the impact on the 2011 proposed rate base.

RESPONSE

a) Kenora Hydro is proposing to include in the rate base for 2011 the smart meter capital deployed as of December 31, 2009, $1,030,168.

b) Kenora Hydro submits that the addition of $500 to the amortization in 2011 was an error and there should be no 2011 OM&A expense relating to the 2010 or 2011 smart meter capital additions.

c) The revenue requirement in 2011 does include $500 of amortization expense on estimated smart meter capital of $15,000 to be purchased in 2011 ($15,000 / 15 years , apply ½ year rule). The amortization of $19,640 includes $19,140 on the base amount from the closing 2010 account of $562,338 (excludes all smart meters), plus a $500 additional expense added onto the amortization on the meter account in error. Once the $500 error is backed out of this expense, there will be no amortization relating to 2010 or 2011 smart meter purchases in the revenue requirement.

d) The rate base proposed for 2011 does not include any capital for smart meters to be purchased in 2010 or 2011. The proposed 2010 additions of $3,000 and in 2011 of $3,500 are not for smart meters.

QUESTION #46

Reference: VECC #21

a) Based on this update, what is the revised weighted effective cost of debt for 2011?

RESPONSE

a) With the updated cost of debt, the new weighted effective cost of debt for 2011 is 2.72% (= $130,275 / $4,797,479).

QUESTION #47

Reference: General

a) In response to the first round of interrogatories Kenora identified a number of corrections/revisions to its initial Application. Additional corrections/revisions may arise in response to the current round of interrogatories. Please provide the following:
   - A schedule that identifies all of the corrections/revisions Kenora is proposing to make to initial Application and for each provide a reference to the relevant IRR and the impact on the rate base (if applicable) and revenue requirement.
   - An updated Revenue Requirement Work Form.

RESPONSE

The following table summarizes the proposed changes for the final rate application model as a result of OEB and VECC interrogatories. The updated cost of capital percentages, along with updated Network and Connection rates will also be included in the final model. These changes will be made once the final recommendations are received from the OEB. At that time, the entire rate model including the Revenue Requirement Workform will be updated and re-submitted.

VECC IR # 47		
Kenora Hydro		
Corrections to Rate Application		
	2011 OM&A Expenses (Reduced) Increased	**2011 Capital Spending (Reduced) Increased**
OEB IR's - Round 1		
OEB IR # 6		
OM&A savings due to PST cost reductions	(13,096)	
	Amortization	
OEB IR # 13	1/2 Yr rule	
Reduce Overhead Conductors Budget	(400)	(20,000)
Line Transformers - Capital Contribution missed	(680)	(34,000)
Main copier - purchase delayed	(750)	(15,000)
Tools, Shop & Equipment reduced budget	(125)	(2,500)
Miscellaneous Equipment reduced budget	(100)	(2,000)
OEB IR # 21		
Increase costs due to LEAP program	3,850	
OEB IR # 22		
Increase costs due to OMERS increase	1,167	
OEB IR # 24		
Error - Reduce City allocated costs	(40,434)	
OEB IR's - Round 2		
None noted		
VECC IR's - Round 1		
VECC IR # 21		
Reduced budgeted interest on LTDebt	(74,776)	
VECC IR's - Round 2		
VECC IR # 42		
Reduced estimated Rate Application costs	(21,053)	
(Total reduction = $84,212, Amortized over 4 yrs)		
VECC IR # 45		
Error - Remove smart meter amortization on additions	(500)	
Total Impact	**(146,897)**	**0**
	2011 OM&A Expenses (Reduced) Increased	**2011 Capital Spending (Reduced) Increased**

APPENDIX A

<u>VECC IR # 34 a) and b) – Communications from Hydro One and Hatch Acres Report</u>

From: jim.thompson@HydroOne.com
Sent: March-29-06 9:50 AM
To: Dave Sinclair
Subject: 15m1-Kenora MS-Tap structure # 8.

Importance: High

VECC 34(a)

Good Morning Dave

I will be beginning my estimates over the next few weeks, for our 2007 work, and was wondering how you made out with the engineers.
Do you believe this will transpire ?

Please advise as to progress made.

Thanks
JT
Jim C. Thompson
Transmission Lines Technician-Dryden
Mailing Address :
Hydro One Network Services
Box 10309
Thunder Bay, Ont.
P7B 6T8
Phone: (807)937-5163 ext 21
Cell: (807)221-9686
Fax: (807)937-5181

Dave Sinclair

From: jim.thompson@HydroOne.com
Sent: May-16-06 1:18 PM
To: Dave Sinclair
Subject: FW: Proposed Relocation of Structure 8 on 115 kV Circuit 15M1

Importance: High

VECC 34(a)

Hi Dave
Please read the attached and forward your proposal to Paul Dockrill. You should touch base with him as soon as possible.

I will estimate and move forward with the replacement of structure 8, 1st quarter of next year, and submit as discussed.

Thanks
Jim

From: DOCKRILL Paul
Sent: Tuesday, May 16, 2006 1:04 PM
To: HUDSPETH Doug
Cc: THOMPSON Jim; VANDERREEST Chris
Subject: RE: Proposed Relocation of Structure 8 on 115 kV Circuit 15M1
Importance: High

Definitely - you can have them send here to my attention.

Just FYI, any **HV relocation** issues are dealt with here by Chris Vanderreest, but I assume replacement of Structure 8 is 'routine', therefore would not be at their cost.

Either way, they can send the proposal to me, thanks,

Paul Dockrill
A/Senior Real Estate Coordinator
Facilities and Real Estate
Hydro One Networks Inc.
P.O. Box 4300
Markham, Ontario
L3R 5Z5
Courier Address:
185 Clegg Road
Markham, Ontario
L6G 1B7
Telephone (905) 946-6248
Mobile (416) 460-7654
Fax (905) 946-6242
Toll Free Number (888) 231-6657 Ext 6248
e-mail address: paul.dockrill@hydroone.com

From: HUDSPETH Doug
Sent: Tuesday, May 16, 2006 1:40 PM
To: DOCKRILL Paul
Cc: THOMPSON Jim
Subject: Proposed Relocation of Structure 8 on 115 kV Circuit 15M1

Hi Paul

The PUC in Kenora is planning to make some changes at Kenora MS that will impact our plant. It is my understanding that we need to reconfigure one or two of our transmission line structures to accommodate proposed changes to their station.

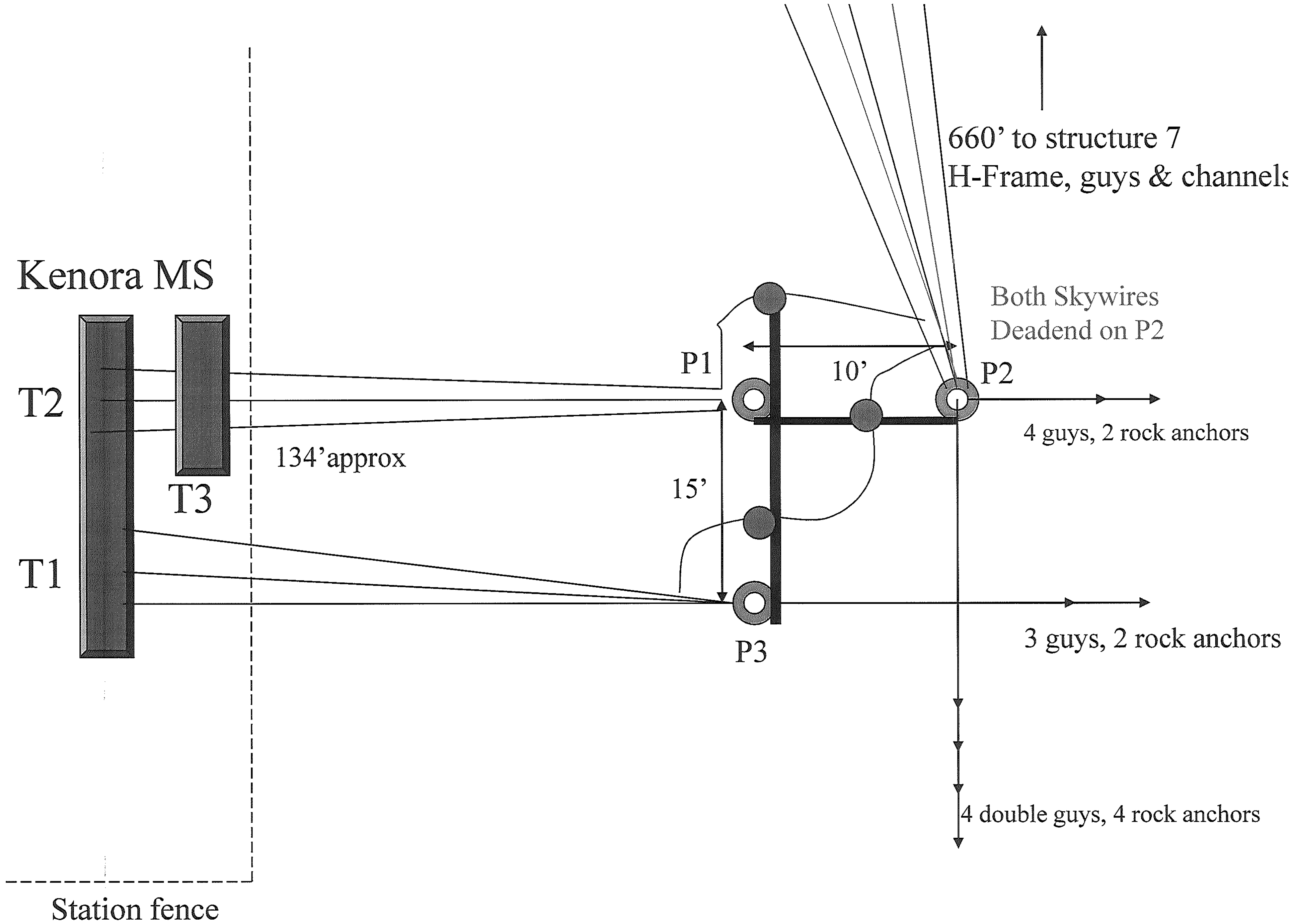
One of the subject structures is scheduled for replacement in 2007. We hope to accommodate part of their request during our replacement of structure 8, but other changes are also required (one or two additional tap structures are required and MSO's are required).

Can we direct the proponent to send their request to you? If not, who should they deal with?

Doug

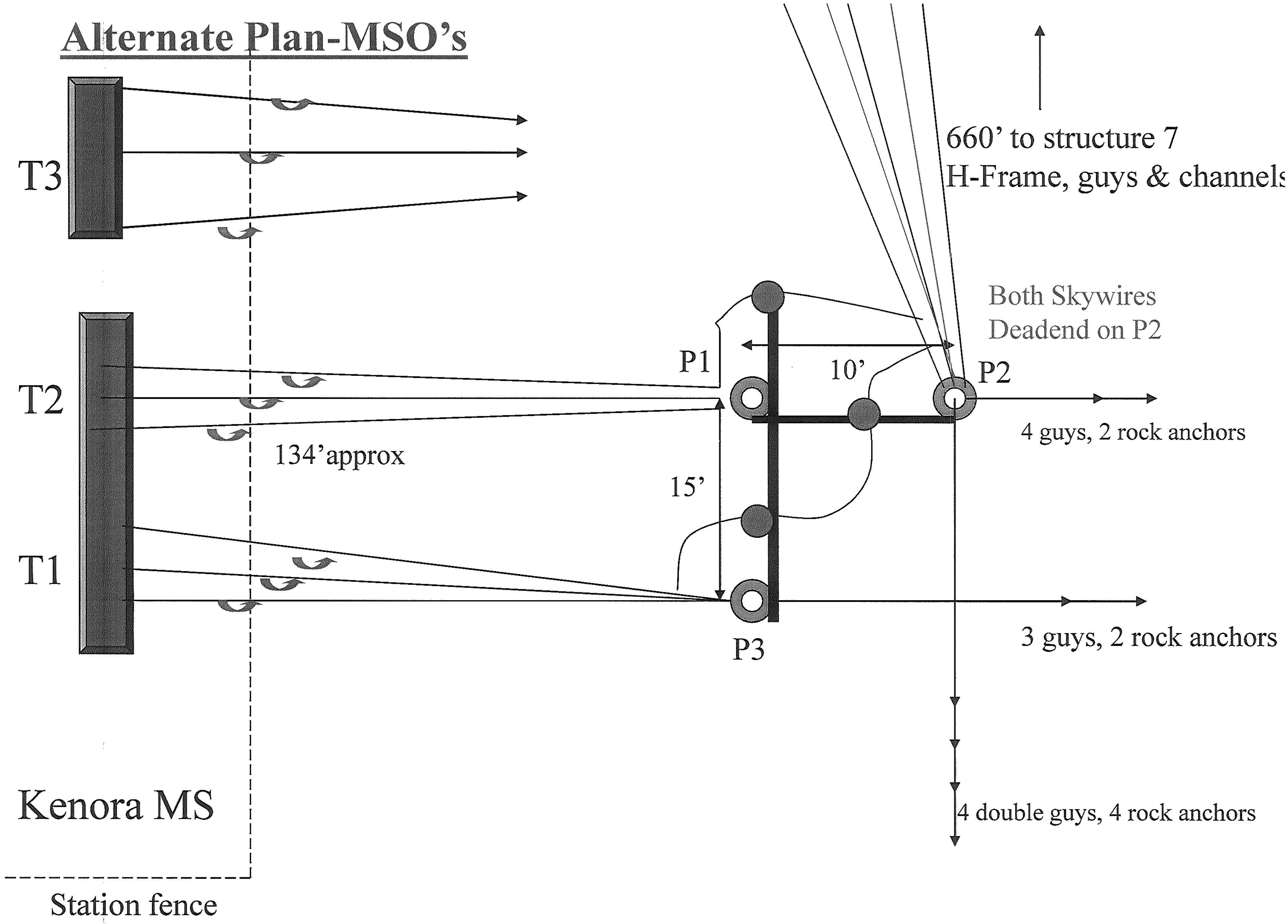
From: THOMPSON Jim
Sent: Tuesday, March 28, 2006 9:06 AM
To: HUDSPETH Doug
Subject: 15M1

<< File: 15M1 str 8.ppt >>

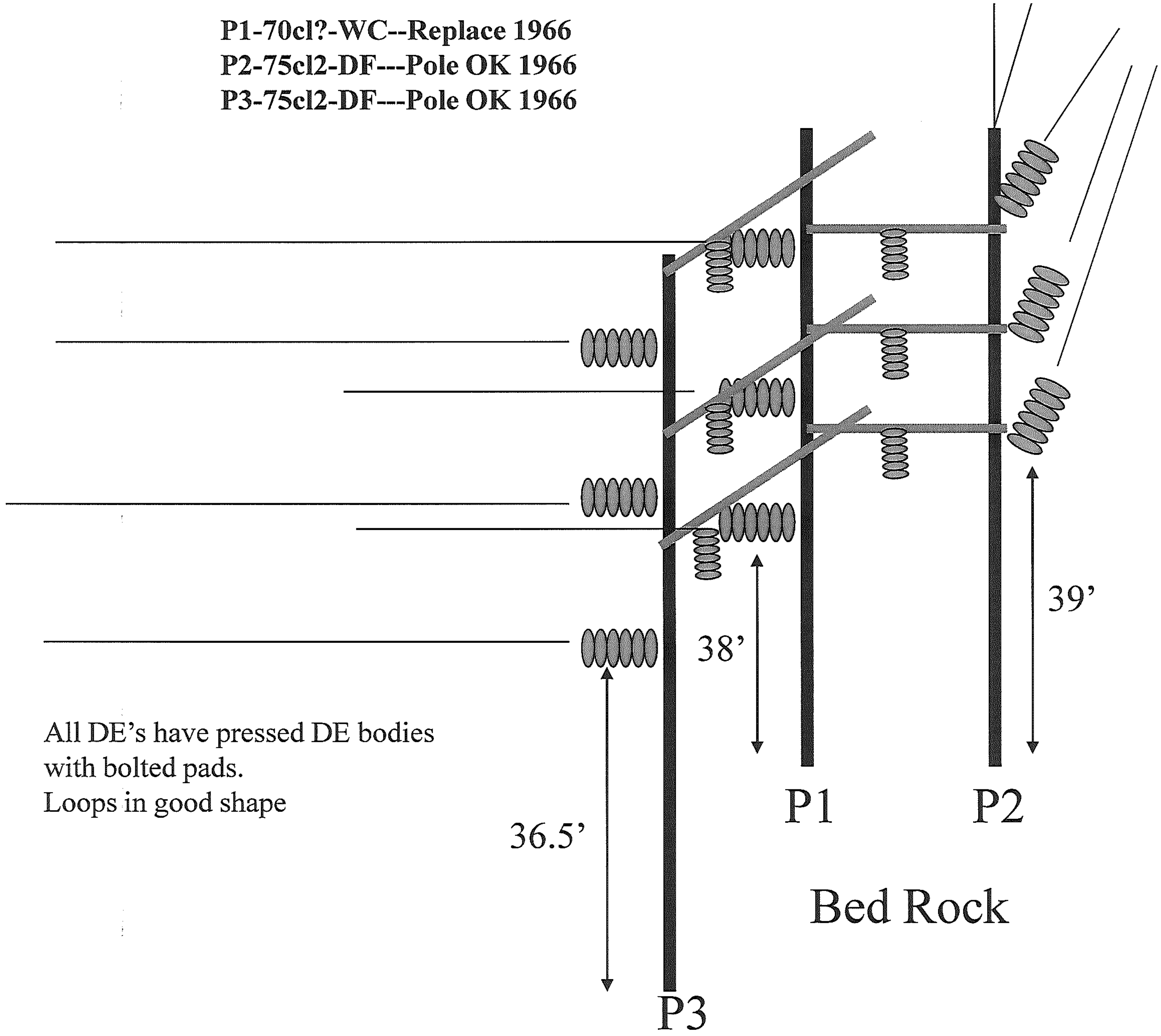


660' to structure 7
H-Frame, guys & channels
Kenora MS
Both Skywires
Deadend on P2
P1
10'
P2
T2
4 guys, 2 rock anchors
134'approx
T3
15'
T1
3 guys, 2 rock anchors
P3
4 double guys, 4 rock anchors
Station fence

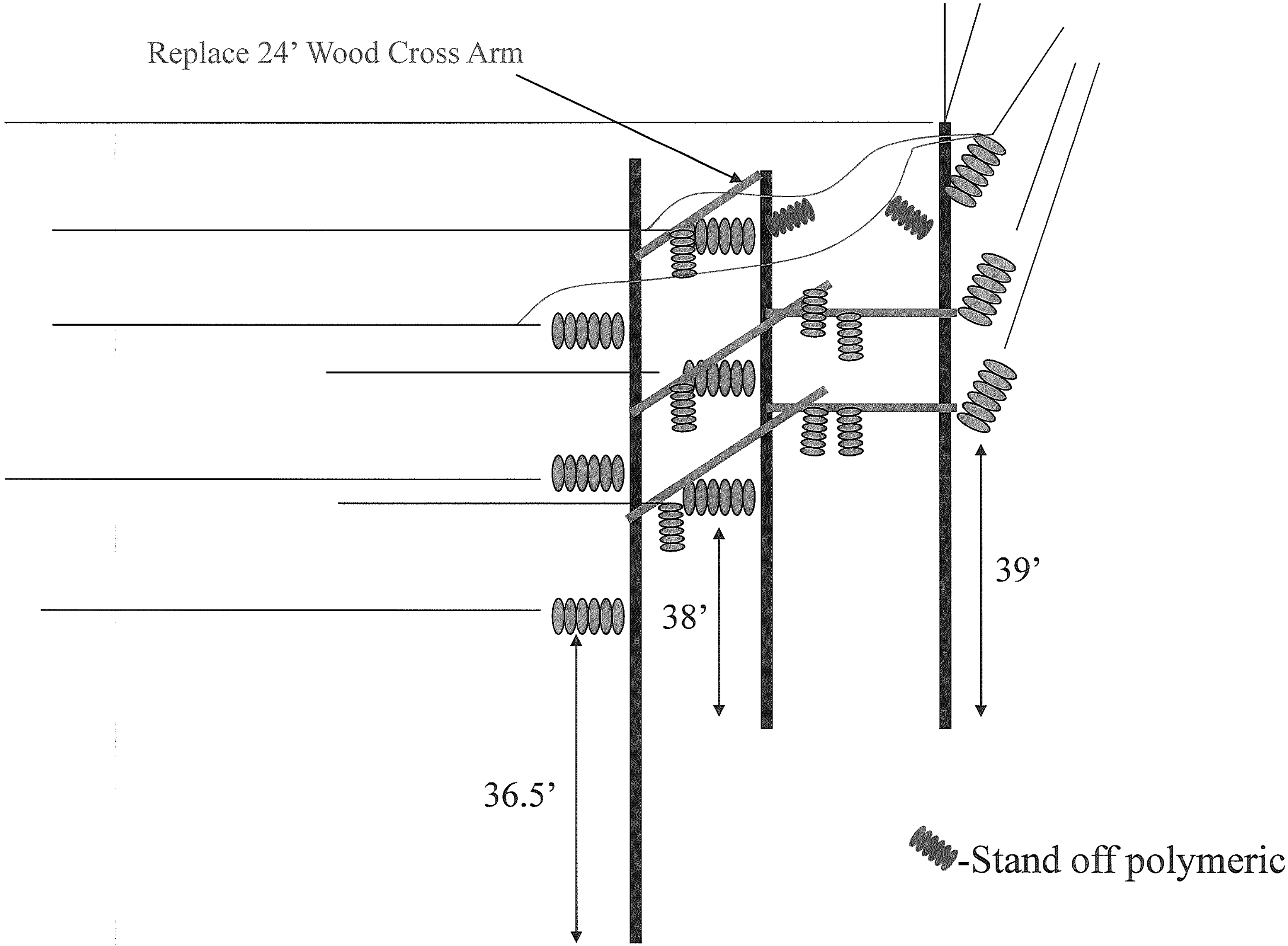
Alternate Plan-MSO's



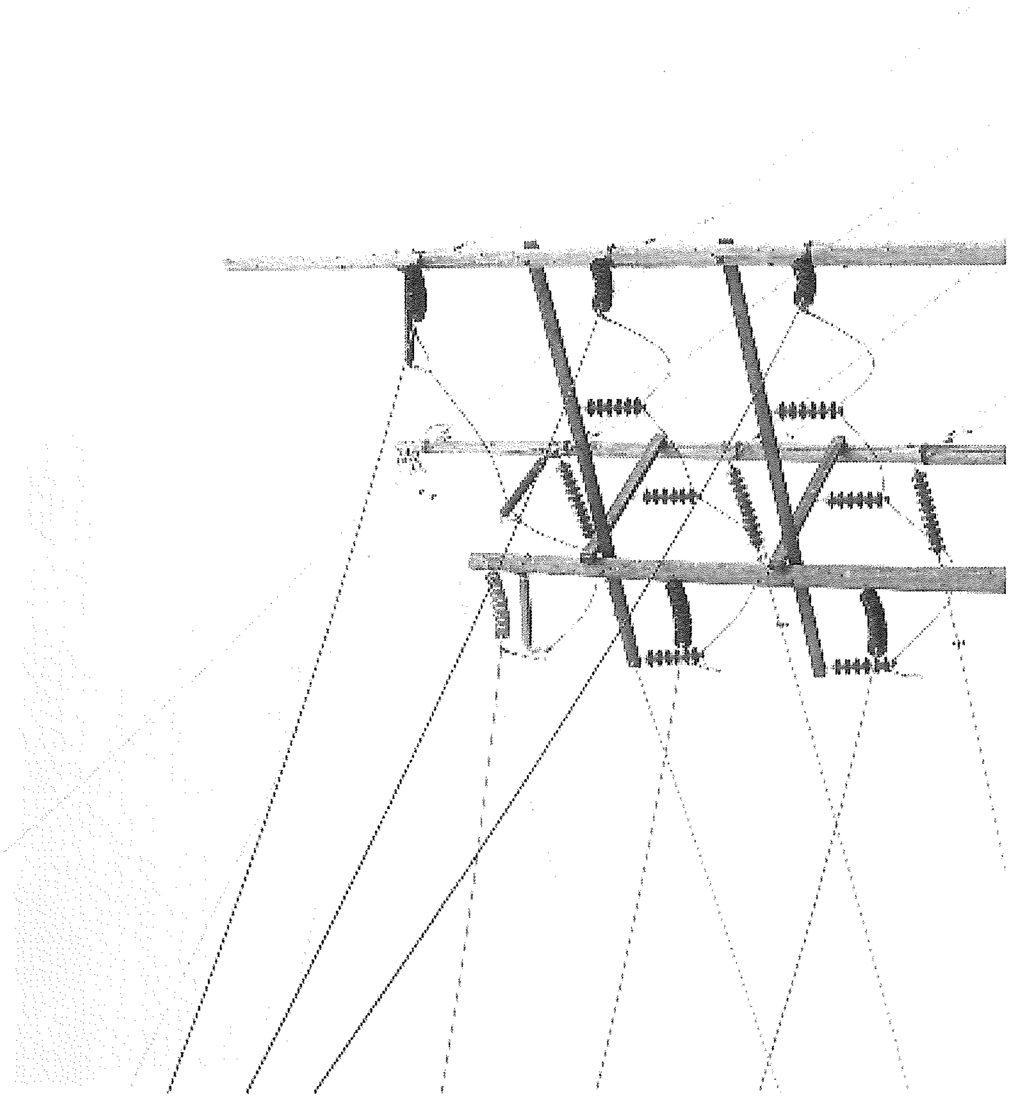
P1-70cl?-WC--Replace 1966
P2-75cl2-DF---Pole OK 1966
P3-75cl2-DF---Pole OK 1966

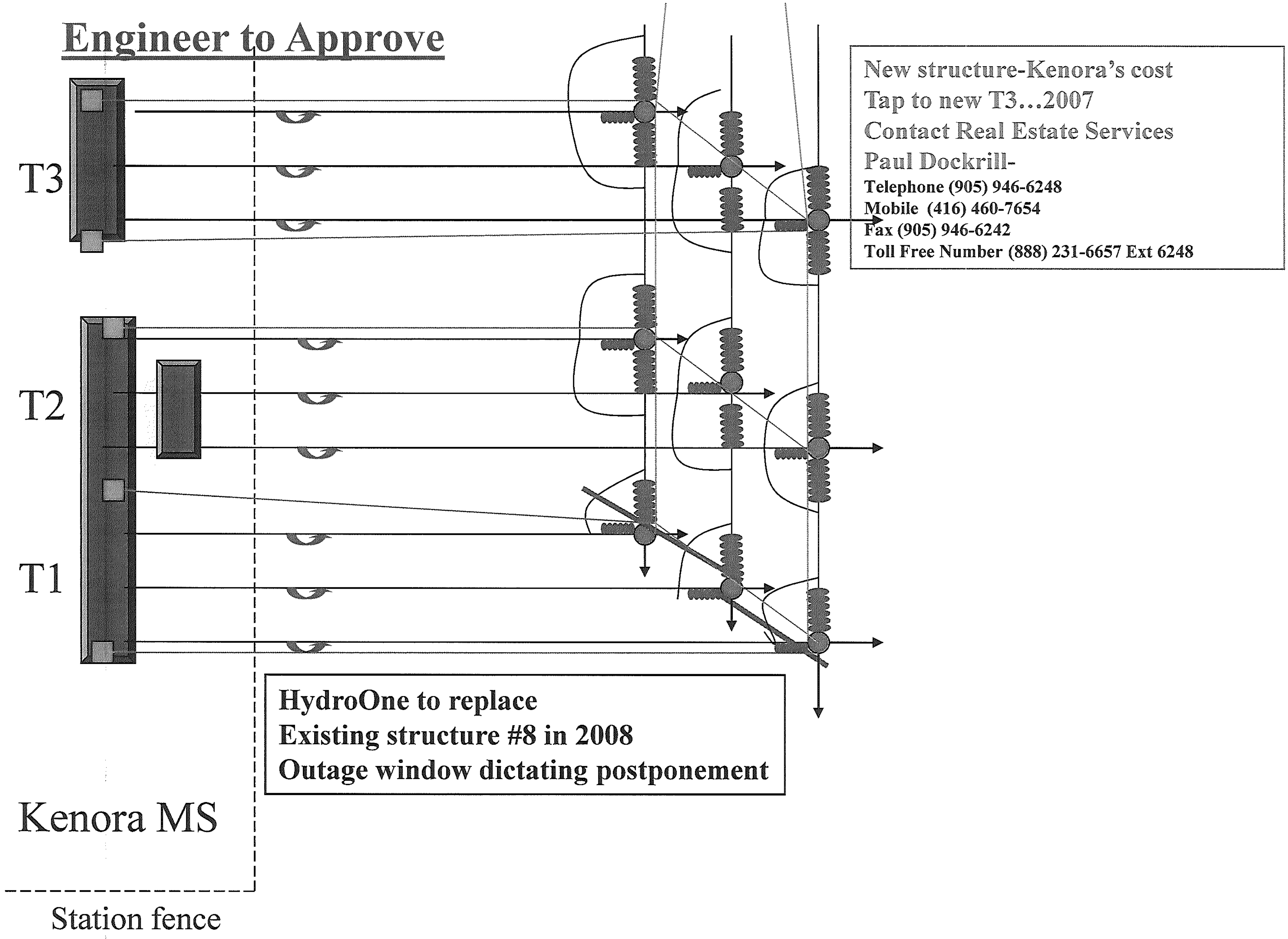


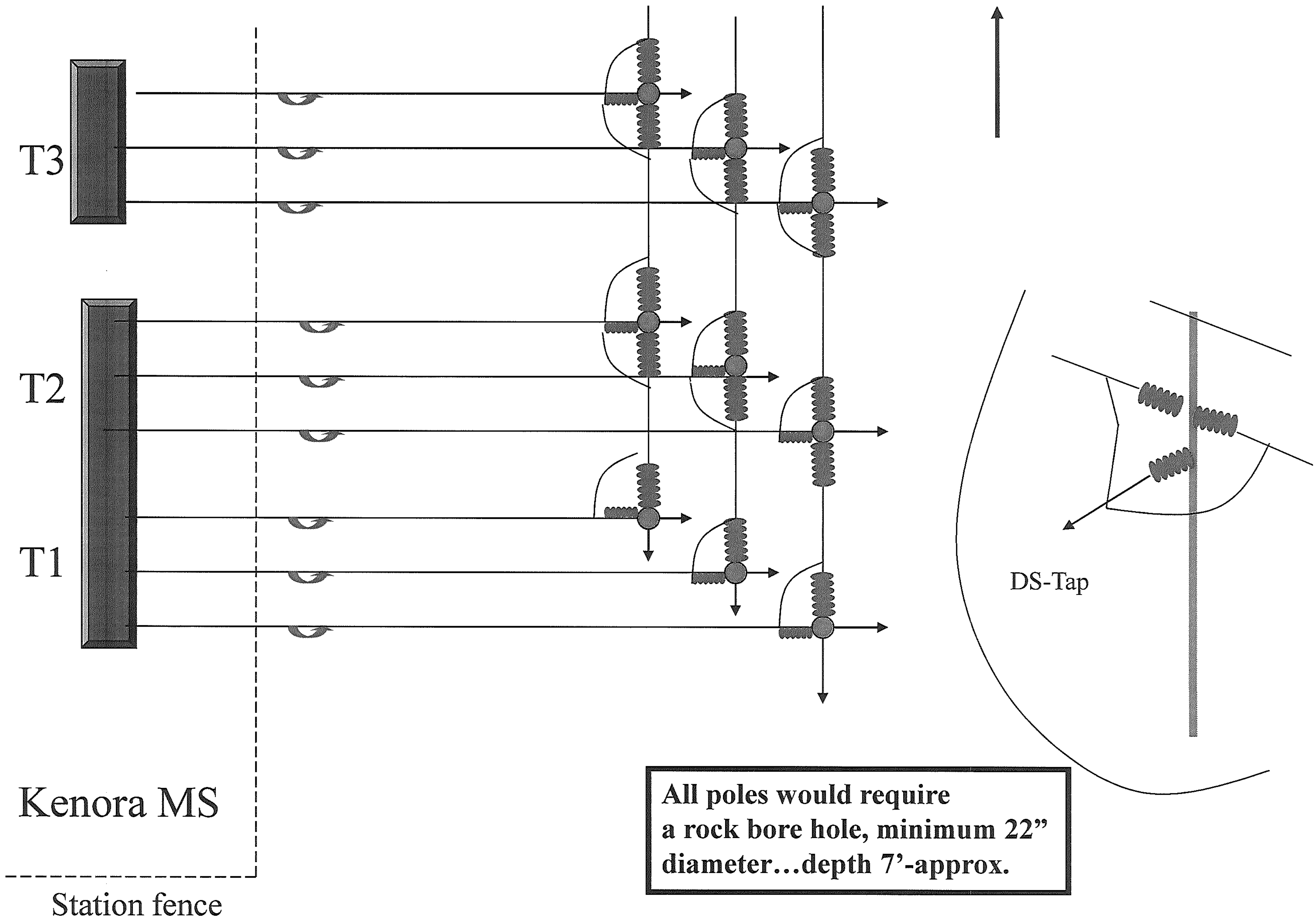
All DE's have pressed DE bodies
with bolted pads.
Loops in good shape



Temporary Repairs made in 2003

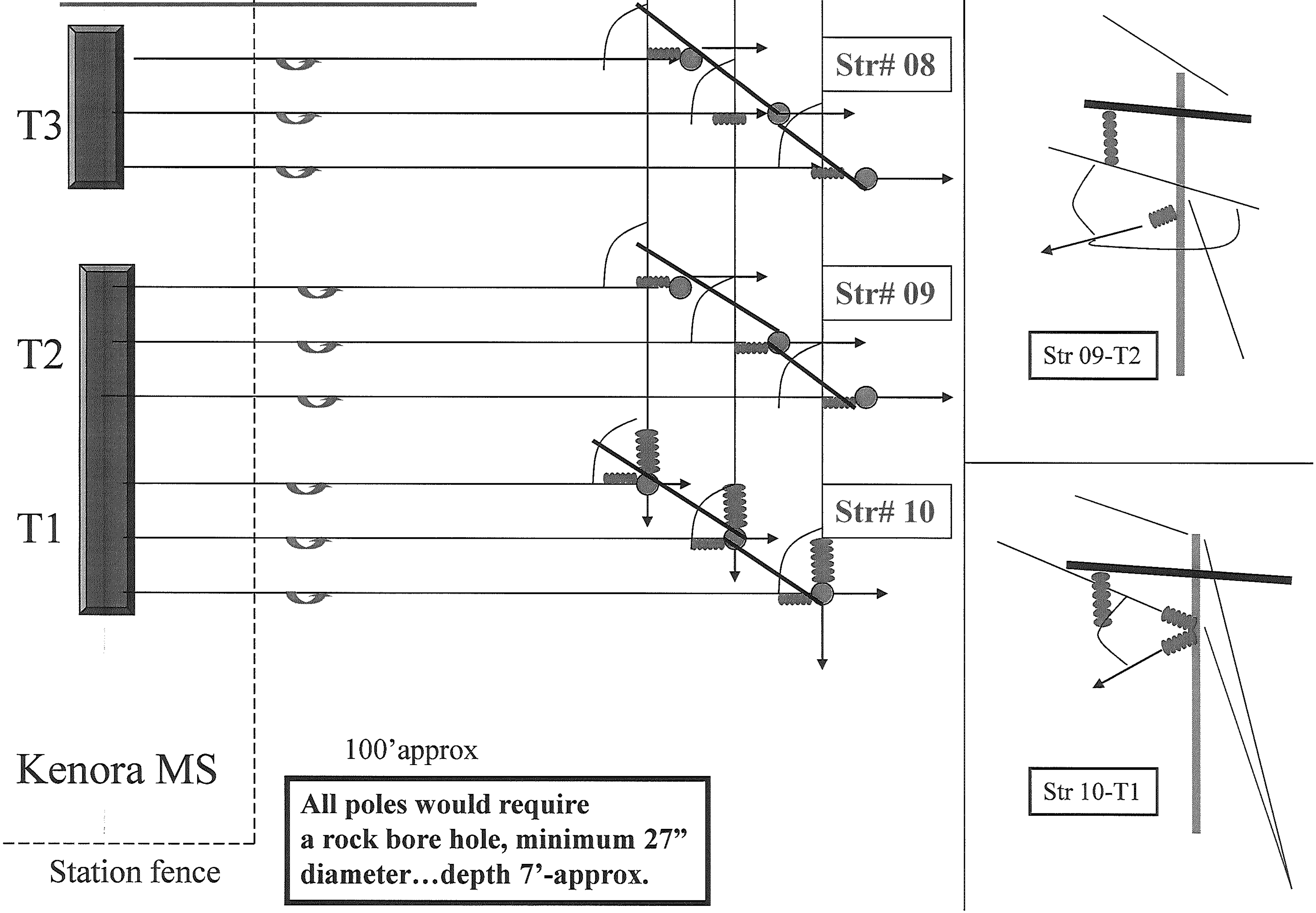



Engineer to Approve
T3
T2
T1
Kenora MS
Station fence
New structure-Kenora's cost
Tap to new T3…2007
Contact Real Estate Services
Paul Dockrill-
Telephone (905) 946-6248
Mobile (416) 460-7654
Fax (905) 946-6242
Toll Free Number (888) 231-6657 Ext 6248
HydroOne to replace
Existing structure #8 in 2008
Outage window dictating postponement



T3
T2
T1
Kenora MS
Station fence
DS-Tap
All poles would require
a rock bore hole, minimum 22”
diameter…depth 7’-approx.

Alternate Plan-MSO's



VECC 34(a,b)

Kenora Hydro
Kenora, Ontario

Substation Review
Phase 1
Draft 2

H-017011_01
June 22, 2006

Hatch Acres
Winnipeg, Manitoba

Table of Contents

1 Background

1.1 Introduction

Hatch Acres was retained by Kenora Hydro Electric Corporation Ltd. to review the condition of the existing substation and to recommend improvements to the station. This Phase I report describes proposed changes to the substation and transmission line tap connection which would improve reliability and maintainability of the station.

Kenora Hydro is the electrical distributor for approximately 6000 commercial and residential customers in the City of Kenora. Formerly a department of the municipality, it now operates as a corporation wholly owned by the City of Kenora. Winter peak load is approximately 24 megawatts, but due to increasing air conditioning load the summer peak is nearly as high. All energy distributed to customers is transmitted through the Kenora Hydro main substation.

Kenora Hydro reviewed the first draft of this report. This revision has been changed to reflect the comments made on the first draft.

1.2 Transmission Line, Substation Equipment and Structure

Kenora Hydro obtains energy from the Hydro One system at 115 kV. A 1.5 km wood pole line connects the Kenora substation to the Hydro One Rabbit Lake transformer station. This line terminates at a three-pole structure east of the Kenora Hydro station. Two sets of conductors connect the substation to the line. One set feeds transformer T1 only, the second set feeds T2 and is tapped for the T3 transformer.

Three 9000/12000 kVA transformers at the substation reduce voltage to a nominal 12.5 kV for distribution. High-voltage fuses protect each transformer. Transformers T1 and T2 were installed in 1966 and feed a double-ended outdoor line-up of disconnect switches, with T1 normally connected to C and D feeders and T2 connected to feeders B and C. Transformer T3 was added in 1981 and feeds a separate line-up of switches for feeders E and F.

The initial substation construction has two bays for T1 and T2 transformers. The steel lattice structure has 115 kV disconnect switches and fuses for each transformer, with a service platform for access.

T3 was added to the station east of T2. A steel H-frame structure was added for the disconnect switch, fuses, and lighting arresters. The T3 structure was aligned with the conductors for T2 so T3 and T2 share the 115 kV tap connection to Hydro One.

1.3 Operating Concerns

The existing switching arrangements do not allow isolation of the 115 kV switchgear for the three transformers. The present arrangement has the effect that isolation of high voltage switchgear for T3 is not possible without also deenergizing T2. During high load periods, the remaining transformer is not sufficient to carry the entire load and so an unacceptable loss of station capacity occurs.

Present-day peak load now matches the forced-air rating of any two of the transformers. For proper redundancy to protect against a failure of any transformer (or high-voltage switch), switching must be provided so that any two of the three transformers can serve the load while the remaining unit is completely isolated.

Planned refurbishment of the existing transformers would extend their service life and increase reliability. The objective would be to install a fourth transformer and switchgear. This would allow any one of the existing transformers to be removed for refurbishment but still allow the full load demand to be supplied with protection against a transformer failure contingency. When the fourth transformer is installed, one unit can be designated as standby. On a planned schedule, each of the original transformers would be sent for refurbishment; over a span of three to four years, each of the original transformers would be exchanged with the standby unit, until all units have been refurbished. Medium-voltage switchgear will minimize load outage time since cable connections need not be changed.

The existing 3-pole structure that terminates the line was installed in 1966. While the poles are believed to be in sound condition, much of their economic life span has passed and replacement of these poles is now planned by 2007. In 2003 damage to a cross-arm occurred and it was removed; three polymer stand-off insulators were installed to support the conductors that had hung off the damaged cross-arm. This incident caused a significant unplanned outage to the City.

Electrical Safety Authority Bulletin 36-1-21, dated January 2006, indicates that the Ontario Electrical Safety Code does not apply to equipment that is part of the Supply Service. However, meeting the minimum requirements of the Ontario Electrical Safety Authority Code would be an objective of any modifications. Kenora Hydro has the option of complying with Ontario Electrical Safety Code and submitting plans to the ESA for review, or use of utility standards in design. The Electrical Safety Authority is currently working with Ontario utilities to formulate a uniform set of standards for utility construction. New construction at the substation must comply with standards for clearances, touch and step potentials, and for ground potential rise.

1.4 Equipment Condition

Principle items of substation equipment are reviewed in ascending order of priority for replacement or upgrade.

Medium voltage metal-enclosed switchgear has been rebuilt and should provide satisfactory service. Routine regular maintenance should be carried out as required, with special attention to maintaining the weather-proof integrity of the switchgear cabinets.

Transformers T1 and T2 are now approximately 40 years old and T3 is nearly 30 years old. These transformers can be considered more than half-way through their economic lives. Continuing regular gas and oil tests are key to assessing the condition of these transformers. In view of the critical importance of these units to the system, annual testing would provide the maximum information possible on which to base maintenance and refurbishment decisions.

High-voltage disconnect switches for T1 and T2 are part of the original equipment of the station. These switches have become a maintenance concern. Infrared scanning may assist in detecting problems with the switch contacts, but the linkage mechanism that operates the switches can fail mechanically. Replacement of switches would reduce these concerns and can be carried out one switch at a time. However, better facilities for transfer of load between transformers would greatly improve the maintainability of the station in general.

Some high-voltage horizontal cap-and-pin insulators for T1 and T2 banks have been replaced in 2002. However, future replacement of insulators would be expedited if additional isolation facilities were installed.

The wood pole structure that forms the termination of the 115 kV line has already shown signs of deterioration. Damaged cross-arms were removed in 2003. These poles are now 40 years old and any upgrade of the station should consider an alternative arrangement that would eliminate the old poles and provide easier access for maintenance of the 115 kV line.

By installing an additional transformer “T4”, and medium-voltage switchgear, sufficient capacity can be gained in the substation to allow for a program of rotation of transformers. A fourth transformer would allow any one unit to be shipped out for overhaul and still provide full capacity and redundancy for the station load.

This modification is the highest priority to assure the continued reliability of the substation.

1.5 IESO Requirements

General technical requirements of the IESO are given in the Transmission Code. The Connection Agreement gives the specific details for a particular customer, and Kenora Hydro has supplied a copy of its Agreement to Acres. Schedule F gives general technical requirements and Schedule H gives the requirements for transformer stations.

Known exceptions to the requirements of the Transmission Code were tabulated in Schedule J of the Connection Agreement. The Kenora Hydro substation is protected by fuses on the high voltage side, so redundant protection systems are not possible. Kenora Hydro does not have any telecommunication equipment for its protection system. Kenora Hydro has no automatic system in place for load shedding; this must be done manually.

The proposed modifications do not affect the line protection for the substation. However, a ground study must be carried out to verify that the ground resistance at the station is acceptable under Schedule F of the Connection Agreement.

Appendix 2 of the Transmission Code, "Transmission System Connection Point Performance Standards", states that the transmission operator may have a maximum fault level of 50 kA at a 115 kV point of connection. The existing fuse protection is rated to interrupt a maximum of 10.5 kA, and the present Hydro One fault level is 1421 MVA or nearly 7.2 kA symmetrical. If the interrupting rating at the station were substantially increased, Kenora Hydro would require higher-rated interrupting devices (transformer protectors, circuit switchers, or circuit breakers). Installation of T4 will not affect primary voltage fault level, but any parallel operation of transformers on the 12.5 kV side would require assessment of fault levels on the distribution network. Since Kenora Hydro does not have differential protection or reverse power protection for the transformers, parallel operation is not permitted by the existing connection agreement.

2 Proposed Modifications

2.1 Alternatives

Kenora Hydro has developed three alternatives for the revised 115 kV lines entrance to the station. In all these alternatives a transformer is installed north of the existing lattice structure; either a new T4 is installed, or T3 is moved.

In the first alternative, T1 and T2 continue to be fed from the existing pole structure (poles P1, P2, and P3) and T3 is fed from new conductors terminating at a new pole structure connecting to the line. The incoming line from the Rabbit Lake station remains with a vertical arrangement of conductors and the transformer tap conductors rotate from vertical to horizontal as they run to the transformer station structure.

In the second alternative, nine new poles are installed and each phase conductor for each transformer terminates at a pole. Three strain insulators are used at each pole, for the three phase conductors. The incoming transmission line tap is configured with conductors in a horizontal plane, and the taps for each transformer also have the conductors arranged horizontally.

The third alternative is similar and also uses nine poles in three sets, with crossarms installed between the poles. The transmission line is supported by vertical insulators below each crossarm. Transformer taps are similar to the second alternative and the conductors are in a horizontal plane.

The first alternative has the advantage of minimal extra construction, but relies on the continued use of the original poles. The other two alternatives require setting nine poles in holes bored in rock, which is costly. The third alternative uses fewer strain insulators and jumpers. Both 9-pole alternatives have the advantage of arranging all conductors horizontally which simplifies access for maintenance and which allows the use of in-line "MSO" isolation jumpers.

Another alternative developed during preparation of this report would have had three new poles installed between the substation fence and the Hydro One tap line, on the Hydro One right-of-way. The existing Hydro One transmission line would be swung over and the existing poles then would be salvaged. Tap conductors to the transformers would leave the poles in a vertical line and would rotate to horizontal position at the substation structures. However, this arrangement exceeded Hydro One's maximum allowed angle of 3 degrees offset on a tangent tower, and so was deemed infeasible.

2.2 New Poles and Line Extension

Installation of a fourth transformer allows for continued load growth and redundancy. The proposed modification to the station discussed in this report is the third alternative, using nine poles and a T4 transformer installed in a new structure north of the existing units. The proposed layout is shown on the drawings in Appendix A.

2.3 Transformer T4 Location and New Structure

A new outdoor line-up and new metering would be installed for T4. The new line-up would contain tie switches that would allow T4 to feed any of the existing busses (B1, B2, or B3). This would allow any two of the transformers to meet the existing load demand, and allow any one transformer to be undergoing refurbishment while still providing protection against a transformer failure.

A new pad will be constructed for the new T4 transformer. A steel lattice structure will be installed with a 115 kV disconnect switch, 115 kV fuse holders and fuses, and provision for mounting the lightning arresters. New medium-voltage cables will be installed between the new T4 and the existing line-up for feeders E and F. The existing revenue metering for T1, T2 and T3 will not be affected. Control circuits and fan power for T4 will be connected to the existing facility.

By maintaining a clear working space on the east side of the existing transformers, exchange of the transformers can be expedited. As transformers are overhauled, they can be rotated through the T1/T2/T3/T4 positions as required for refurbishment of each of the existing units.

2.4 Grounding and Bonding

It is a requirement of the Canadian Electrical Code that the ground potential rise of the station must not exceed 5000 V, and that touch and step potentials are controlled. Grounding conditions at the station are expected to be poor due to the shallow soil and exposed rock. A soil resistivity survey is required for the proper design of the extension of the substation grounding grid.

The existing ground grid does not cover the area to be used for T4. The ground grid must be extended to cover the area within the fence. The conceptual substation design used to prepare a feasibility-level cost includes a close-spaced ground grid to minimize gradients within the station, and for additional ground rods to improve ground resistance. No off-site grounding is assumed, other than bonding the sky wires of the transmission line to the structures. In the present substation, the perimeter fence is separately grounded. Fence grounding must be studied to determine if appropriate step and touch potentials are maintained.

A grounding mat will be provided at the new disconnect switch operating handle. The disconnect switch handle will be bonded to the grounding mat to prevent differences in potential due to ground fault currents.

2.5 Isolation of 115 kV Switches

An isolating point for the station 115 kV switches can be provided by installation by Hydro One of a mid-span opener ("MSO") assembly in each phase wire. This consists of an in-line strain insulator and a flexible jumper, secured to the incoming line with a live line clamp. This is strictly a non-load-break isolation point. These isolation devices would be owned and operated by Hydro One. If maintenance is required on one of the Kenora Hydro 115 kV switches, the transformer can be isolated initially with the switch and then a live-line crew can open the jumpers at the MSO to provide a visible isolation between the supply and 115 kV switches.

3 Capital Cost Estimate

3.1 Basis of Estimate

The proposed solution will use a new transformer. A new lattice structure, 115 kV disconnect switch, 115 kV fuses and medium-voltage cable are included. Minimal allowance has been made for site civil preparation. The existing fence around the site is retained; the interior fence must be removed to provide for the new structure. The existing T3 structure, disconnect switch, fuses and foundation are left in place. The cost of moving T3 off its existing pad can be deferred since it can be left in place until scheduled refurbishment of one of the other transformers.

A new line-up would be installed for T4. New unfused tie switches would be installed on each of the existing T1, T2, and T3 line-ups and connected by underground cable to T4 to allow any one transformer to be removed and the load fed from another transformer.

A steel lattice structure is assumed for the new T4 bay. Later investigation may suggest alternatives such as a wood pole or tubular steel structure.

Cost of a fourth spare 9/12 MVA transformer with manual off-load tapchanger has been included as a new unit price.

No detail design work has been completed. Cost elements shown in the estimate are based on standard construction cost tables and costs obtained for similar work elsewhere. Foundation design is assumed typical for these structures.

The sequence of installation to minimize outages has not been reviewed. Coordination of line work and construction with Hydro One is necessary.

No modification of the protection and control system is included. Installation of transformer protectors, circuit switchers or circuit breakers is not included on the basis that the existing fuses provide adequate protection. New metering and instrument transformers will be installed for the new T4 switchgear. No new communication or control equipment will be installed and controls will remain in the existing building.

A detailed survey of the existing substation site and equipment is required. No comprehensive drawing is available for the current layout of the station. The time required for preparation of this survey is included in the cost estimate.

Grounding has been priced based on a close spacing of grounding conductors and a large number of ground rods. The assumption is that total GPR at the station can be controlled if the new ground grid is bonded to the existing grounding system. Costs of a soil resistivity survey and a computer study of the ground grid are shown.

3.2 Capital Cost

A breakdown of the capital cost for the new structure, transformer, switchgear, poles and reconnection of lines is given on the attached spread-sheet (Appendix B). The estimated cost is $1,400,000. Further detailed design would be required to reduce uncertainties in this estimate.

4 Detailed Engineering Phase

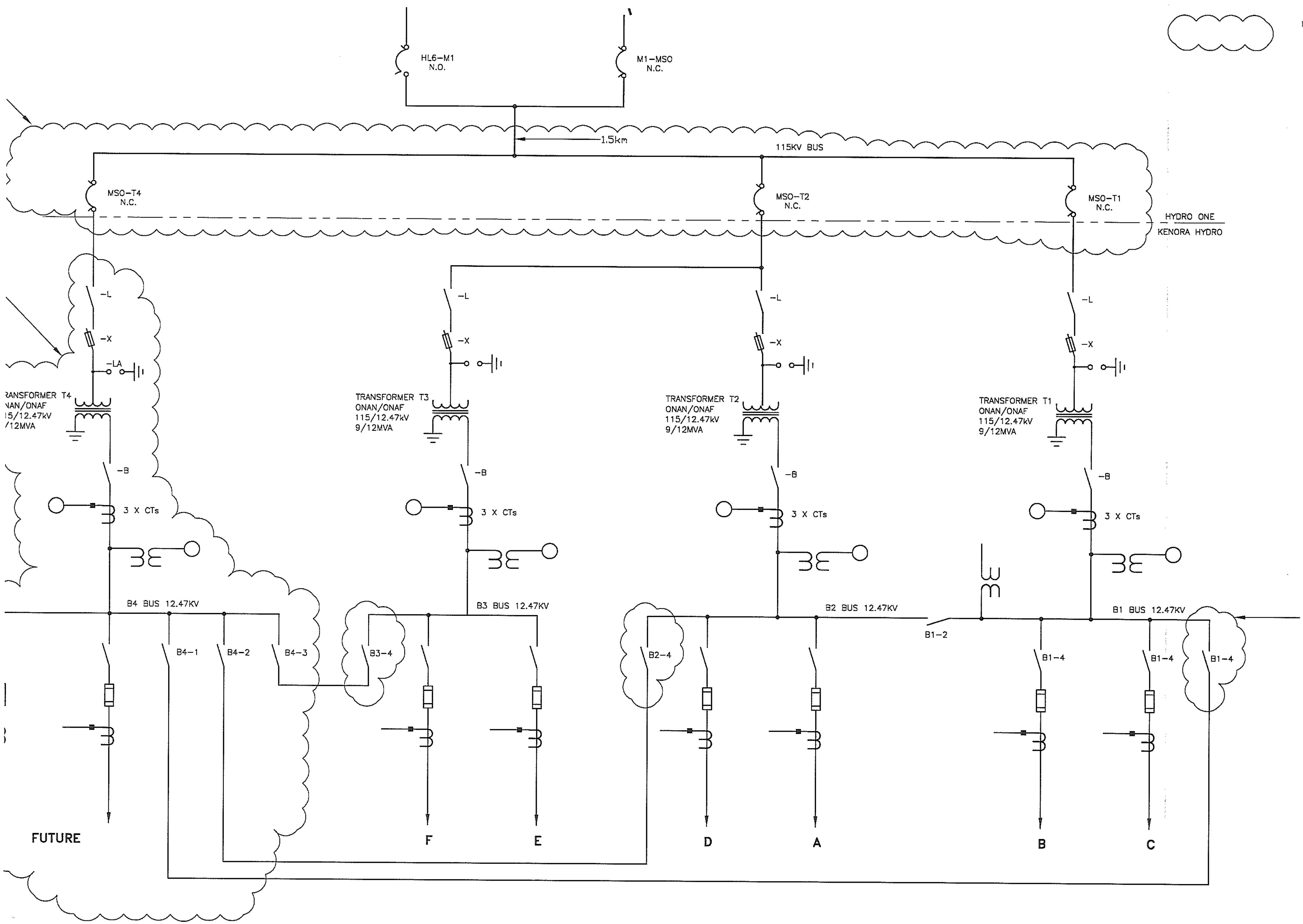
If Kenora Hydro decides to proceed with the modifications described, additional engineering will be required. Detailed engineering sufficient for capital expenditure preparation, tendering and construction would include the following drawings and studies:

Accurate survey of all existing structures, poles, fences, equipment, located with respect to legal survey boundaries, including elevation grid
Ground resistivity survey
Outages plan
Grounding study
Preparation of drawings: • (Revised) Single line drawing • Site plan drawing, equipment layout and site preparation • Grounding plan and grounding details • Foundation plan and details • Structure plan, elevation • Structure details • Pole line elevation and details • Buried cables plan and details • Cable schedules • Three-line diagrams showing CT and PT phasing Interconnection wiring diagrams Bill of Material
Preparation of purchasing and installation specifications
Preparation of tender documents
Construction cost estimate

Estimated cost of these services is shown on the capital cost spreadsheet.

Appendix A

Substation Layout Drawings



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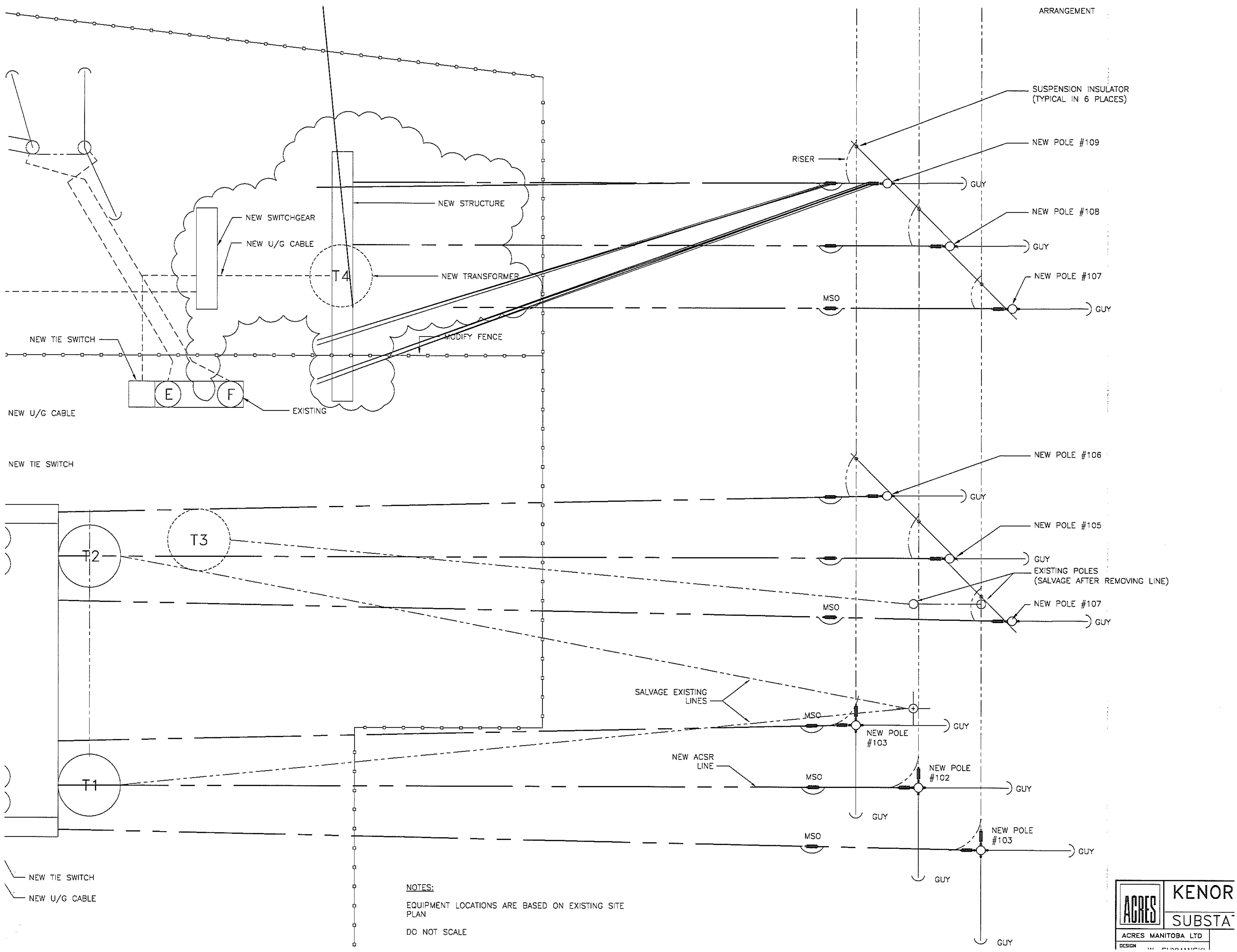

NOTES:

EQUIPMENT LOCATIONS ARE BASED ON EXISTING SITE PLAN

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SUBSTA

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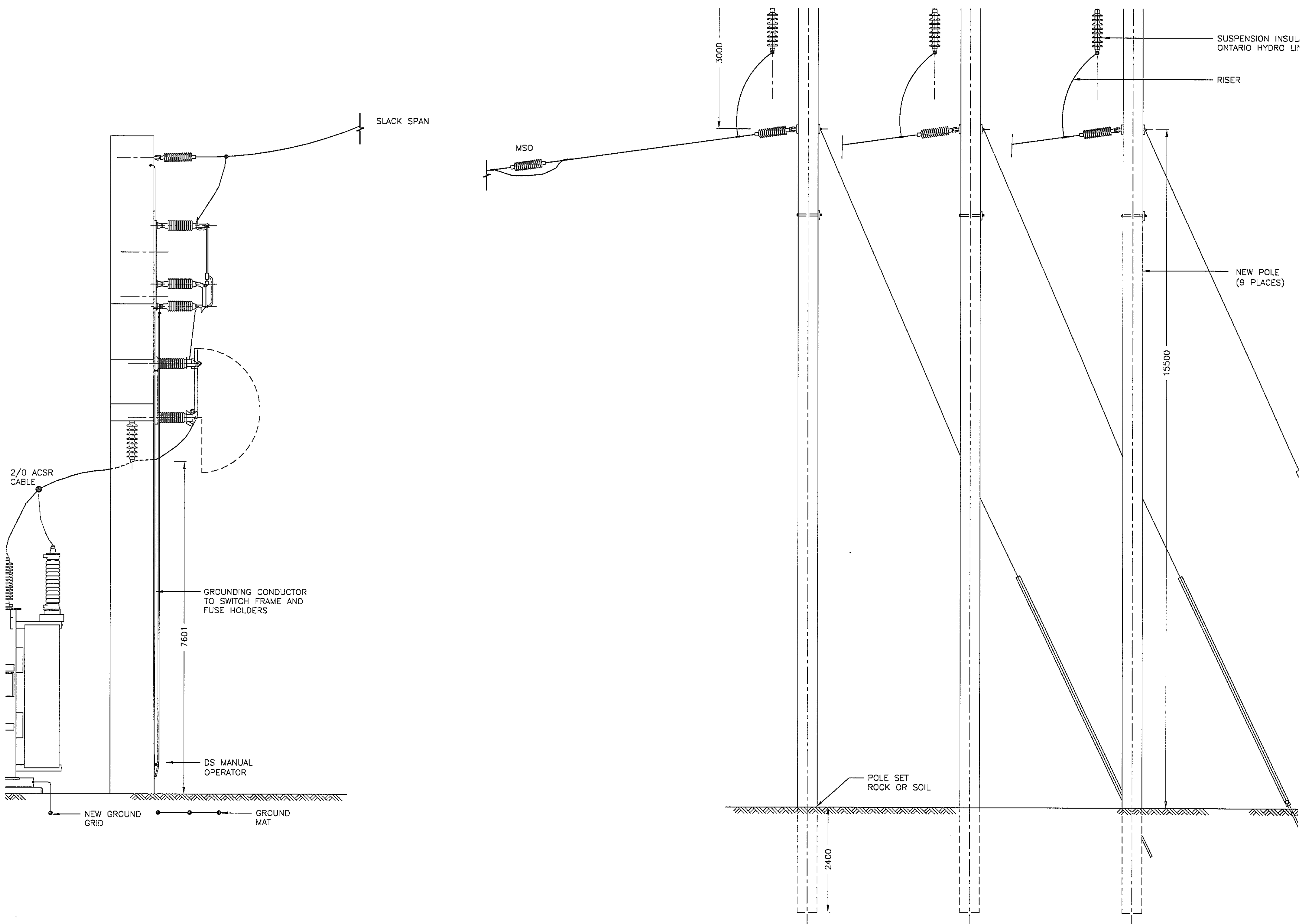
DESIGN



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Appendix B

Cost Estimate Breakdown

ACRES MANITOBA LTD
Estimate of Capital Cost - Feasibility Level
Client: Kenora Hydro
Project Location: Kenora, Ontario
Project Title: Substation Upgrade (9-Pole Structure)

Acres Project No. H01701101
Draft 2
Prepared By: WTS
Checked By:
Date: 22-Jun-06
Labour rate ($/hr): $50.00

Item No.		Description	Unit	Quantity	Labour Hrs/Unit	Labour $/Hr	Labour Total	Material Unit Price	Material Total	TOTAL
1	**Civil/Structural**									
		Detailed site survey, with elevations	ea	1	48.0	75	3,600	$500	500	4,100
		Lattice structure for T4 transformer,	ea	1	80.0	50	4,000	$45,000	45,000	49,000
		Foundations for lattice	ea	2	12.0	50	1,200	$1,000	2,000	3,200
		New foundation for T4	ea	1	24.0	50	1,200	$3,000	3,000	4,200
		Site grading and fill	sq m	600	0.05	50	1,500	$15	9,000	10,500
		Crushed rock 150 mm	sq m	600	0.05	50	1,500	$8	4,500	6,000
		Fence - assume can use existing								0
		Erection crane 1 week	wk	1				$5,600	5,600	5,600
2	**Electrical**									
		Transformer 115 kV/12.47 kV, 9/12 MVA, new, off-load tap changer	ea	1	100.0	50	5,000	$600,000	600,000	605,000
		Disconnect switch 115 kV manual operator	ea	1	100.0	50	5,000	$18,000	18,000	23,000
		Station post insulators	ea	3	4.0	50	600	$350	1,050	1,650
		Surge arresters station classs	ea	3	10.0	50	1,500	$4,425	13,275	14,775
		Fuse holder , three phases,115 kV w/fuses	lot	1	8.0	50	400	$16,000	16,000	16,400
		ACSR 266.8 kCMIL	m	600	0.03	50	900	$3	1,800	2,700
		Suspension and strain insulator assemblies	ea	18	8.0	50	7,200	$600	10,800	18,000
		Poles 75 foot Class 2	ea	9	15.0	50	6,750	$1,700	15,300	22,050
		Pole bore in rock	ea	9	19.0	50	8,550	$0	0	8,550
		Crossarms 24 ft.	ea	4	8.0	50	1,600	$1,500	6,000	7,600
		Hardware, clamps, bolts, guy per pole	lot	9	14.0	50	6,300	$425	3,825	10,125
		Rock anchors	ea	3	15.0	50	2,250	$315	945	3,195
		Grounding 4/0 bare	m	700	0.03	50	1,050	$4	2,800	3,850
		Ground rods 3 m x18 mm in rock trenches	ea	20	8.0	50	8,000	$30	600	8,600
		Cad-welds	ea	175	1.0	50	8,750	$35	6,125	14,875
		ACSR joints and dead-ends	ea	18	8.0	50	7,200	$226	4,068	11,268
		New outdoor switchgear line up, 4 cells	ea	1	225.0	50	11,250	$93,500	93,500	104,750
		Feeder 12.47 kV to new lineup	lot	1	80.0	50	4,000	$7,000	7,000	11,000
		Feeders to T1, T2, T3 line-ups	lot	1	240.0	50	12,000	$24,000	24,000	36,000
		Tie switches T1, T2, T3 line-ups	ea	3	30.0	50	4,500	$18,000	54,000	58,500
		Ground mat for manual switch	ea	1	8.0	50	400	$600	600	1,000
		Guy strand and overhead ground	m	355	0.1	50	1,775	$1	355	2,130
		Ground resistivity survey	lot	1	64.0	50	3,200	$1,000	1,000	4,200
		Guy insulators, guy guards	ea	3	2.0	50	300	$100	300	600
		Bucket truck rental and operator	week	3	40.0	50	6,000	$3,200	9,600	15,600
		New metering for T4	Lot	1	16.0	50	800	$3,200	3,200	4,000
		Move 115 kV conductors from existing poles (by Hydro One)	Lot	1		50		$50,000	50,000	50,000
		Install MSO strain insulator/jumper/hot line clamp (by others)	Lot							0
				0						0
3	**Demolition**									
	Remove and salvage existing P1, P2, P3 by Hydro One		lot	N/A			0			0
							0			0
							$124,700		$1,013,300	$1,138,000
		Engineering	Lot							$57,000
Subtotal							$124,700		$1,013,300	$1,195,000
			PST		8%					$95,600
			GST		7%					$83,650
PROBABLE TOTAL CAPITAL COST (+/- 30%)										**$1,374,300**

3601

VECC 34(a,b)

HATCH ACRES

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Tel: 204-786-8751 • Fax: 204-786-2242 • www.hatchacres.com

E-MAILED

July 12, 2006
File P-AQ 0204

Kenora Hydro Electric Corporation Ltd.
PO Box 2680
215 Mellick Ave.
Kenora, Ontario
P9N 3C6

Attention: Mr. David Sinclair
President and CEO

Dear Mr. Sinclair:

Proposal for Engineering Services
Substation Upgrade – Phase II

Hatch Acres is pleased to submit our proposal to carry out a Phase II engineering design for upgrade to the Kenora Hydro 115 kV substation.

Background
During Phase I of the work, a conceptual single-line diagram and layout of the proposed installation was developed. The intention of the substation upgrade is to purchase and install a fourth transformer and designate the T3 unit as a spare. This will allow planned overhaul of all transformers while still maintaining full substation capacity. A new 115 kV line arrangement will simplify station maintenance and improve security of the supply, so that any single 115 kV component can be worked on without a city-wide power interruption. Improved road access to the station would speed up the exchange of any transformer with a spare, reducing the cost of planned outages and potentially reducing the duration of emergency repairs.

A phased approach to capital expenditures is necessary. Expenditure plans require a budget estimate of costs and must be ranked in priority order. The Phase I report identified a conceptual substation layout and budget estimate. Phase II consists of a detailed design based on the selected option from the Phase I report. Kenora Hydro is now required to conform to the Ontario Electrical Safety Authority code (CEC with Ontario amendments) for its installations.

Project Stages
Construction of the substation will be staged to coordinate with Hydro One activities, to allow for only two city-wide outages, to allow for delivery of equipment and to obtain approvals from Hydro One, IESO, and ESA.

In Stage 1, a detailed site survey will be completed to record the present location of all equipment and structures, to identify lot lines, and to obtain site contours. Results of a soil resistivity study will be input into ground grid calculation and design. A new station single line diagram showing existing and new equipment will be prepared. A specification for the new power transformer will be prepared, so that Kenora Hydro may purchase this long lead time item. A plan drawing of the substation equipment layout will be prepared so that all nine poles can be located. A site improvement plan, showing all new grading and road access will be prepared. Drawings and specifications will be sent to IESO, ESA and Hydro One so that all regulatory applications can be made in preparation for the connection of the new transformer. A cost estimate will be prepared. This stage must be completed before the Hydro One pole replacement and a necessary city-wide outage, in the spring of 2007. Where possible, site improvement construction may be started in the fall of 2006 to expedite the following year's activities. During this stage, the feasibility of combining activities into a single city-wide outage will be developed.

In Stage 2, civil design of foundations will be completed. Purchase specifications for the switchgear and arresters will be prepared to support Kenora Hydro's purchase of these items. Data from the transformer and switchgear vendors will be required to complete foundation design. These drawings must be completed to allow for foundation construction in spring 2007.

In Stage 3, drawings will be prepared for interconnection of the new transformer, new metering, and new switchgear. This would permit installation of the new transformer during a city-wide outage planned for the fall (September) 2007, if a second outage is necessary. After the completion of construction, record drawings will be produced. Operation and maintenance manuals for the new equipment will be compiled from manufacturer's sources, and a station write-up completed. The 12.47 kV network will be investigated for proper switching procedures, and a switching manual prepared for future reference by Kenora Hydro personnel.

Scope of Work

We understand that Hydro One will replace the existing three-pole structure for the transmission tap, and that they will provide three additional poles for the T1 and T2/T3 taps (total six poles). Hatch Acres will provide all engineering for the additional (T4) transformer location and three additional poles, ground grid, metering, 115 kV switchgear, 12.47 kV switchgear, and 12.47 kV feeders up to the existing 12.47 kV dip poles.

The following is our understanding of Hatch Acres scope of work:

- Carry out a survey of the existing substation site, identifying equipment locations, foundation locations, legal limits of property, existing transmission line location, and elevations and grade relative to an on-site reference point.
- Communicate and coordinate plans with ESA, IESO, and Hydro One.

- Carry out limited assessment of soil depth at site, in selected areas.
- Provide a specification for work to obtain a soil resistivity survey. This is to be performed by others.
- Provide a specification for a power transformer 115 kV to 12.47 kV 9/12 MVA.
- Provide a specification for purchasing an outdoor 12.47 kV fusible switchgear line-up.
- Provide specifications for station structures, cables, 115 kV switchgear and surge arresters.
- Revise station single-line diagram.
- Prepare an accurate, comprehensive site plan based on survey data.
- Prepare a site geotechnical plan showing new fill required inside the station fence and new fill and grading for an access road; analyze drainage of site.
- Provide layout details for new and existing electrical equipment, including relocation of guy anchors where required.
- Provide civil design for foundations for the transformer and switchgear.
- Design pole structures for 115 kV incoming line, confirm structural adequacy of poles.
- Review pole structure plans with Hydro One; confirm Hydro One supplied and installed poles.
- Review substation structure shop drawings.
- Review shop drawings for transformer and switchgear.
- Prepare electrical interconnection drawings for transformer, metering, switchgear.
- Prepare electrical drawings for 12.47 kV feeders from switchgear to poles.
- Based on soil resistivity survey, design a station grounding system to limit ground potential rise and touch and step potentials to Electrical Safety Code limits.
- Obtain data on 12.47 kV feeder layout, review operating procedures for switching load between transformers, prepare new switching instruction guide for operations.
- Collect operation and maintenance material from equipment suppliers, prepare O&M manual and station write-up.

Work Not Included
Tendering, procurement, bid evaluation, construction supervision and commissioning are not included, but are optionally available. Factory test witness for the transformer is not included, but is shown as an option under fees below.

Deliverable Items

Stage		Drawings	Reports and Specifications
1	Survey and layout up to pole structures	Site Plan with survey data and property lines. Site Improvements plan – showing drainage, fill, grounding, fences and access. Single line diagram. 115 kV line entrance layout.	Soil resistivity. Grounding study. Transformer purchase specification. Protection coordination review for IESO and ESA. Engineer's cost estimate.
2	Foundations for equipment	Foundation Plan and details. Electrical equipment layout plan and elevation. Bill of Material drawing. Substation structure shop drawings by vendor.	Switchgear (12.47 kV) purchase specification. Lightning arresters (115 kV) purchase specification. Switchgear (115 kV) purchase specification. Review of shop drawings for structure, switchgear and transformer.
3	Transformer T4 installation	Electrical interconnecting wiring diagram. Buried cable layout/details. Cable schedules. Connection diagrams for transformer and switchgear. Metering schematic and connection diagram. (Record issue of all drawings).	Study and operation manual for 12.47 kV feeder switching. Operation and maintenance manual for new substation equipment.

Project Team
The electrical work will be carried out by Mr. William Shymanski from our electrical department, with specialist support, as required, from our Oakville Transmission & Distribution Group. The work will be coordinated by Alan Heartfield, Electrical Department Head.

Civil structural work will be done by Mr. Blair Fraser of our civil department. Geotechnical work will be done by Mr. Philippe Pantel and drainage analysis and modelling by Ms. Angela Swanson, of the Geotechnical department. Site survey work will be carried out by Mr. Ricardo Rodriguez.

Engineering Fee
With the deliverables as shown above, the three stages of the Phase II proposed scope of work are (taxes extra):

Stage 1	$48,900
Stage 2	$20,300
Stage 3	$25,300

Total, not including taxes	$94,500

Factory test witness of the transformer is not included in the above fees. Test witness would be $4,400 and travel expenses (outside of Winnipeg) invoiced at cost.

Terms and Conditions
Hatch Acres proposes to undertake these services in accordance with our lump sum Terms and Conditions which are attached and form part of this proposal.

Project Schedule
Our staff is available to begin work on this project immediately. The survey would be scheduled after authorization to begin the work. Detailed foundation design would require layout and weight of the new and existing transformers, and the new switchgear. Soil resistivity results must be supplied to complete ground grid design. Milestone dates would be as follows:

Authorization to proceed	July 19, 2006
Stage 1 drawings and specifications	September 2006
Stage 2 drawings and specifications	March 2007
Stage 3 drawings and specifications	August 2007
Record drawings	October 2007

We trust that the above proposal is acceptable to you and look forward to the opportunity of working with you on these projects. Should you have any questions please contact myself or Alan Heartfield at 1-888-824-0441.

Yours very truly,

Richard Marynick, C.E.T.
Manager Industrial and
Regional Projects

WTS:sep
Attach

Kenora Hydro Electric Corporation Ltd. accepts the terms and conditions and authorizes Hatch Acres to proceed with the proposed work.

Signature for
Kenora Hydro Electric Corporation Ltd.

Date July 25/2006

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VECC 34(b)

Kenora Hydro Mellick Station
T4 Bay Electrical Equipment Budgetary Cost

	Equipment Description	Manufacturer	Part #	Qty	Cost CND$ Unit	Cost CND$ Total	
1	115-12.47/7.2kV, 9000kVA, 55C ONS, 3 Phase 60Hz, BIL 550kV Power Transformer	GEC	Serial # 286228	1	0	0	Equipment available
2	HV Fuse 138kV, 250A Max, BIL 650kV, 180° opening complete with Mounting (SMD-2B) with silicon-house composite Polymer Insulators and live parts	S&C	186519-P, 3980	3	8,084	24,252	Budgetary cost from S&C
	SMD-2B Fuse unit	S&C	489065R5	3	2,660	7,980	
3	138kV, 1200A,100kA MOM withstand, BIL 650kV Gang operated center break disconnect switch C/W switch handle operator	Cleaveland/Price	C26A028G03	1	15,500	15,500	Budgetary cost from Cleaveland & Price
4	Station class surge arrester for 115kV L-L system, duty cycle 96kV, MCOV 76kV with 4 hole NEMA Pad, three (3) 8.75" BC mounting holes and ground clamp	Hubble Power/OB	31476-3001	3	1,200	3,600	Budgetary cost from Ohio Brass
5	477 MCM ACSR (Hawk) Conductor			150	30	4,500	Assumed
6	Station Post Insulators 138kV, BIL 650kV, ANSI TR288, Light Grey	Lapp	J-315288-70	9	450	4,050	Typical cost assumed
7	Aluminum alloy terminal with hex head terminal clamp for connecting ACSR cable 4/0-1113MCM to 4 hole NEMA pad.	Sefcor	AFNC-1139-4A	15	59	885	Budgetary cost from Sefcor
8	Aluminum alloy terminal with hex head terminal clamp for connecting ACSR cable 4/0-1113MCM to 2 hole NEMA pad.	Sefcor	AFNC-1139-2A	6	63	378	Budgetary cost from Sefcor
9	12.47kV Weatherproof 1200A pad mounting switchgear comprised of, One Incoming cubicle with load interrupter One Metering cubicle with revenue grade VTs and CTs Two feeder cubicles with fuse, load break switch and RM CTs. 5m straight 12.47kV bus section One transformer box to busduct adapter One bus duct 90° Bend One bus duct to switchgear adapter One bus duct support bracket			1	99,000	99,000	S&C quoted 82,000$ and JR Stevenson 85,000-99000$
10	Aluminum alloy T connector for connecting 4/0-1113MCM run cable to 4/0-1113MCM tap cable	Sefcor	ACRCT-1139-1139	3	62	186	Budgetary cost from Sefcor
11	Cable pull box 20"x20"x12"	Hoffman	WS202012SS	1	500	500	Typical cost assumed
12	Aluminum alloy bus support for 4/0-1113MCM ACSR cable	Sefcor	AVCA-1139-5	9	75	675	Budgetary cost from Sefcor
13	1C-500MCM Teck cable for outgoing feeders	Anixter		270	90	24,300	Bugetary Price from Anixter
14	CT, PT and Heater Cable Teck Cable, 4C#10AWG	Anixter		400	8	3,200	Bugetary Price from Anixter
	Electrical Equipment Total					**189,006**	

Notes:

1 The installation and installation equipment rentals are not included.
2 Civil, structural and raceway costs are not included.
3 Project management and engineering costs are not included.
4 Contingency is not included and costs are for year 2007.