DISTRIBUTION LINE LOSS

1.0 INTRODUCTION

This exhibit presents a discussion on the types of line losses, the reason they exist, an estimate of the technical and non-technical line loss associated with Hydro One's Distribution System as a whole, recommended Distribution Loss Factors and how Hydro One manages distribution line losses.

The term "distribution line losses" refers to the difference between the amount of energy delivered to the distribution system from the transmission system and the amount of energy customers are billed. Distribution line losses are comprised of two types: technical and non-technical (the description of each type is presented in the sections below).

It is important to know the magnitude and causality factors for line losses because the cost of energy lost is recovered from customers.

As a result of the composition and scale of the Hydro One distribution system it is not economic to provide metering and the supporting processes capable of measuring line losses directly. Since energy meters do not total data for the same periods, and load varies over time, a direct measurement of actual losses is not feasible. Instead, Hydro One relies on studies which are designed to calculate the magnitude, composition and allocation of system losses based on annual aggregate metering information for energy purchases, energy sales and system modeling methods. These studies are conducted with the assistance of industry experts in this field to ensure appropriate scientific methods and modeling techniques are utilized in establishing the magnitude, composition and allocation of losses.

This exhibit also addresses the three directives from the 2006 Distribution rates proceeding RP-2005-0020/ EB-2005-0378 related to losses, which are discussed in Exhibit A, Tab 17, Schedule 1 and repeated below for convenience:

1. The Board is of the view that either a less expensive metering program, or a second effort to evaluate line losses using current load data and local experience, may provide loss factor estimates that are more acceptable and credible to stakeholders.

2. The Board does accept the submissions of intervenors regarding the expected benefits of the $4.75 million expenditure and directs Hydro One to include in its next main rates case filing a budget and a work plan to implement all the cost-effective line-loss reduction suggestions contained within the Kinetrics study. If Hydro One concludes that any of the recommendations in the Kinetrics study should not be implemented, it must clearly demonstrate the reasons for that position, and an accompanying budget and work plan for its preferred implementation plan.

3. The Board expects Hydro One to continue its efforts to refine line loss factors as they affect the bills of individual LV customers

2.0 TECHNICAL LOSSES

Technical losses on distribution systems are primarily due to heat dissipation resulting from current passing through conductors and from magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated.

Hydro One issued a Request for Proposals (RFP) to carry out an independent assessment of technical losses on Hydro One's distribution system. The work was awarded to Kinectrics Inc., a leading authority on distribution systems and distribution losses in particular.

The report prepared by Kinectrics and entitled "2007 Recalculation of Distribution System Energy Losses at Hydro One" is presented in Appendix A of this Exhibit. Consistent with the requirements of the first Board directive noted in Section 1.0, the Kinectrics report uses new load profiles that became available in 2006 for determining customer group (i.e. Sub-Transmission, Primary, and Secondary) losses, as well as considering new customers that were identified as part of the work to update the study.

This report forms the basis for Hydro One's estimates on the magnitude, composition and allocation of losses on the System. The report establishes the Distribution Loss Factors (DLFs) for the various customer groups and also provides the rationale for Hydro One's distribution loss reduction program.

Hydro One owns primarily a rural distribution system with some pockets of urban development. Hydro One's distribution system technical losses are estimated to be 5.86 percent of the energy delivered to the distribution system and consist of estimated 5.26 percent for losses incurred in the distribution system and 0.6 percent of losses that relate to transformer losses at transmission stations and high-voltage distribution stations, which supply the distribution system.

Losses occur on subtransmission lines, distribution lines, station transformers, distribution transformers and secondary services to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that are dependent on the loading.

2.1 Comparison of Typical Urban vs Rural Losses

The losses breakdown by equipment components for the distribution system of typical urban and rural utilities is shown in the table below. Typical urban area losses are 3.6, on average, of energy sold and can range from 2 percent to 5 percent. Typical rural area losses are 7.3 percent, on average, of energy sold and can range from 4 percent to 10 percent.

Table 1: Typical Urban vs. Rural Losses by Equipment*

Component	**Estimated Loss as a Percentage of Energy Sold**	
	Typical Urban	**Typical Rural**
Subtransmission lines	0.1	0.7
Station power transformers	0.1	0.7
Distribution lines	0.9	2.5
Distribution line transformers no load	1.2	1.7
Distribution line transformers load	0.8	0.8
Secondary lines	0.5	0.9
Total	3.6	7.3

* From Table 4 on page 46 in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One."

2.2 Hydro One Losses Estimate

Hydro One's distribution system losses, as determined by the Kinectrics study presented in Appendix A, are summarized in the table below.

Table 2: Hydro One Losses Estimate by Equipment*

Component	Estimated Loss as a Percent of Energy Sold
Subtransmission lines	2.24
LV Distribution station transformers no load	0.21
LV Distribution station transformers load	0.19
Distribution lines	1.49
Distribution line transformers no load	0.78
Distribution line transformers load	0.16
Secondary lines	0.19
Total	**5.26**

* From Table 1 on page 1 in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One." Note: This table does not include transformation losses (0.6%) from transmission stations and high-voltage distribution stations (HVDSs), which are included in Hydro One's Total Distribution Loss Factors.

The total annual energy loss in Hydro One's distribution system is estimated to be about 5.26 percent of the energy sales, which compares to a value of 5.05 percent in the 2005 Kinectrics study. The main reason for the difference is attributed to the use of improved load profile information used with the current study. This is in line with typical losses incurred by other utilities considering Hydro One's mix of rural and urban customers.

3.0 NON-TECHNICAL LOSSES

Non-technical losses occur as a result of theft, metering inaccuracies and unmetered energy. The following sections are a discussion on each of these items.

3.1 Theft of Power Losses

Theft of power is energy delivered to customers that is not measured by the energy meter for the customer. This can happen as a result of meter tampering or by bypassing the meter.

Hydro One manages theft of power by inspection of the meter for tampering or bypassing during meter reading activities, monitoring anomalies during bill preparation and in cooperation with police activities.

3.2 Metering Inaccuracies Losses

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters. All energy meters have some level of error which requires that standards be established. Measurement Canada, formerly Industry Canada, is responsible for regulating energy meter accuracy.

Hydro One manages energy losses due to metering inaccuracies through a meter accuracy verification program.

3.3 Unmetered Losses

Unmetered losses are situations where the energy usage is estimated instead of measured with an energy meter. This happens when the loads are very small and energy meter installation is economically impractical. Examples of this are street lights and cable television amplifiers.

3.4 Estimate of Non-Technical Losses

Non-technical losses have been established by reviewing losses from theft, meter inaccuracies and unmetered energy in other jurisdictions. Based on the Kinectrics analysis which included reviewing the non-technical losses value from utilities across North America, United Kingdom and Australia, a value of 1.2% was recommended as a reasonable estimate. This is the same value as in the previously filed 2005 Kinectrics report.

4.0 LOSS ALLOCATION

To appropriately allocate the cost of losses to the different rate classes applied to distribution customers, it is necessary to estimate the losses in Hydro One's distribution system attributable to sub-transmission, primary distribution and secondary distribution sub-systems.

Within each of the sub-transmission, primary distribution and secondary distribution groups of customers, there are differences among the losses incurred by customers in relation to the energy used. For example, delivering electricity to a customer at the end of a long secondary distribution line would entail more loss than a customer using the same amount of electricity upstream on that line.

Although different customers will have characteristically different loss factors, individual customers are not billed by individual loss factors. It is not practical to accurately measure or model each specific customer's loss factor. Therefore, losses are allocated to customers based on those customers using similar elements of the distribution system, and they are billed at a Distribution Loss Factor (DLF) based on the losses incurred by that entire group.

The estimated values for the DLF for each of the customer classes are based on the Kinectrics study presented in Appendix A of this Exhibit.

4.1 Sub-transmission System Customers

To serve sub-transmission class customers, electricity flows through sub-transmission feeders, which operate at relatively high voltage levels that range between nominal voltages of 44kV and 13.8 kV. Since lines operating at higher voltage levels experience less energy loss per amount of energy delivered than lower voltage lines, serving sub-transmission class customers generally involves lower losses as a percent of energy delivered, compared to customers served from lower voltage facilities. Almost all distribution customers will be served from a feeder that originates from the sub-transmission system, so their DLF will include the losses from sub-transmission equipment.

Consistent with the third Board directive noted in Section 1.0, Hydro One asked Kinectrics to provide a study to identify site specific losses for sub-transmission connected (i.e. LV) customers and will include the results of this study in the evidence to be submitted as part of the rates portion of this Application to be filed in October 2007.

4.2 Primary Distribution Customers

These customers are connected to primary distribution lines, which function at voltage levels ranging between 12.5 kV and 2.4 kV. At these lower voltages, for every unit of energy delivered, primary distribution lines generally lose more energy (per length of line) than sub-transmission lines. Moreover, most primary class customers are served through Low Voltage Distributing Stations (LVDS), who in turn receive supply from the sub-transmission system further upstream. Energy is lost within both the LVDS transformers and in the lines emanating from them. This results in more energy lost per amount delivered to this Primary class of customers than to Sub-transmission customers.

4.3 Secondary Distribution Customers

These customers receive electricity after it has passed through the sub-transmission system, primary distribution lines and LVDSs. This results in several stages of transformation before being sent at low voltage through secondary distribution lines that operate at voltages as low as 120/240V. Pole-top, pad-mount and underground step-down transformers that step-down voltage from primary distribution system to the secondary distribution system generally lose more energy per quantity delivered than do low voltage distribution stations. The pole-top, pad-mount and underground transformers function at much lower load factors because they serve less diverse groupings of lower-volume customers (e.g. a small number of residences). Therefore, they often operate at little or no load, though still drawing power for their operation thus sustaining relatively high losses per energy delivered. In addition to all the losses associated with the transformation to the secondary voltage, the secondary distribution lines themselves lose a substantial amount of energy per unit delivered.

The total losses attributable to the secondary distribution customers also include the losses in the sub-transmission and primary distribution systems upstream in the delivery chain. As a result, these customers generally incur higher losses per unit delivered than any other customer class.

4.4 Comparison of the Estimated Total Loss Factor with the Total Loss Factor in the Existing Rate

The table below compares Total Loss Factors (TLF), applicable to the existing rates, with the ones estimated in the Kinectrics study for the three customer classes.

Table 3: Comparison of Existing TLF with TLF from Revised Study*

Customer Type	TLF in Existing Rates	Estimated TLF from 2007 Study
Embedded LDC and Subtransmission Customers	3.4%	4.4 %
Primary Customers	6.1%	7.4%
Secondary Customers	9.1%	10.0%

* From table on page viii in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One."

TLFs include the Distribution Loss Factor (DLF) and the 0.6% for transformer station losses.

For all the customer classes the TLFs based on the Kinectrics study results are higher than the TLFs included in the existing rate. The difference is due to the use of an improved methodology which includes losses of detailed system elements thereby providing more accurate results for the different customer classes and total distribution losses.

Hydro One has been applying practices and continues to apply practices that mitigate financial impacts on future rates to the extent that it is economically feasible. These practices are described below.

5.0 HYDRO ONE LOSS MANAGEMENT

5.1 General Practices

Hydro One manages losses in the following ways, where it is cost-effective to do so:

1. Technical evaluation of projects - When Hydro One evaluates projects, the cost of losses is considered in selecting the preferred alternative. Standard planning practices include the development of options, which would reduce system losses. These include consideration of more efficient and larger conductors, distribution at higher voltages, phase balancing and power factor correction where it is economical to do so.

2. Voltage conversion projects – In many cases, by-passing and thus providing capacity relief for distribution stations by supplying some of the incremental loads from high voltage feeders (typically 27.6 kV) is considered as an alternative, with benefits of loss reduction. These projects are also considered as an alternative when distribution stations need to be replaced due to end of life considerations.

3. Reducing load on heavily loaded feeders – Unloading heavily loaded feeders by installing capacitors, or transferring load to alternate feeders or new feeders can also be an effective means of reducing losses and is utilized, where economic.

4. Ongoing System Loading Reviews – This is standard planning practice that identifies system performance, assets where loads are approaching rated capacities and identifies opportunities for loss reductions. Resulting projects may include phase balancing, voltage improvement, power factor correction, voltage

upgrades, conductor upgrades and larger system modifications. The system planning approach is outlined in Exhibit C1, Tab 2, Schedule 3.

5.2 Specific Initiatives

The existing Hydro One distribution system was designed and built assuming specific load growth rates and loading patterns. However, in some cases these assumptions do not materialize as forecasted. As a result, some feeders end up loaded in a sub-optimal manner from a perspective of minimizing losses. This situation presents an opportunity to further minimize losses on the Hydro One distribution system.

To uncover the extent of these opportunities Hydro One contracted Kinectrics in 2005, as part of 2006 Distribution rates proceeding RP-2005-0020/EB-2005-0378, to identify cost effective initiatives for Hydro One to reduce its distribution system losses. The 2005 Kinectrics study identified $12.75 million in economical investments that could be made to reduce line losses. In the 2006 Distribution rates proceeding Hydro One Distribution proposed $8 million in economic loss reduction initiatives, which have been substantially completed as part of the CDM program, as discussed in Exhibit D1, Tab 3, Schedule 5. The $8 million expenditure was based on the practicalities (available resources and equipment) to achieve a program of this magnitude involving numerous designs, with the intention of follow-up assessments concerning the feasibility of completing the remaining high level loss reductions identified by Kinectrics.

As part of the follow-up exercise, Hydro One requested Kinectrics to confirm their estimate of economic loss reduction initiatives based on new load profile data that became available in 2006 and greater detailed information on the Hydro One distribution system. The updated estimate of economic loss reductions is included in the 2007 losses study provided in Attachment A to this Exhibit. The updated Kinectrics' study has identified economic loss reductions to be about $6.5 million. The updated Kinectrics' scope of work is consistent with Hydro One's loss reduction initiatives that are underway, and as such, no further specific loss reduction initiatives, over and above the on-going efforts described in Section 5.1 above and in the paragraph below, are proposed in this Application.

Hydro One Distribution currently evaluates all relevant aspects of the distribution system including conductor size, loading, phase balance and other situations with a view to minimizing losses, as described in Section 5.1. Kinectrics' 2007 study recommendations on the benefits of changing out conductors will be incorporated into our general practices, where appropriate. Hydro One will also undertake a review of purchasing agreements to ensure that the purchasing practices do obtain the most cost effective transformers, taking into consideration Kinectrics' work on this topic.

2007 RECALCULATION OF DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No: K-013111-001-RA-0001-R01

July 27, 2007

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Transmission and Distribution Technologies

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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Hydro One, PO 36200 dated August 22, 2006.

REVISIONS

Revision Number	Date	Comments	Approved
R01	July 27 2007	Added a sentence stating that implementation of the loss reduction program began in 2006.	

2007 RECALCULATION OF DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No.: K-013111-001-RA-0001-R01

July 27, 2007

EXECUTIVE SUMMARY

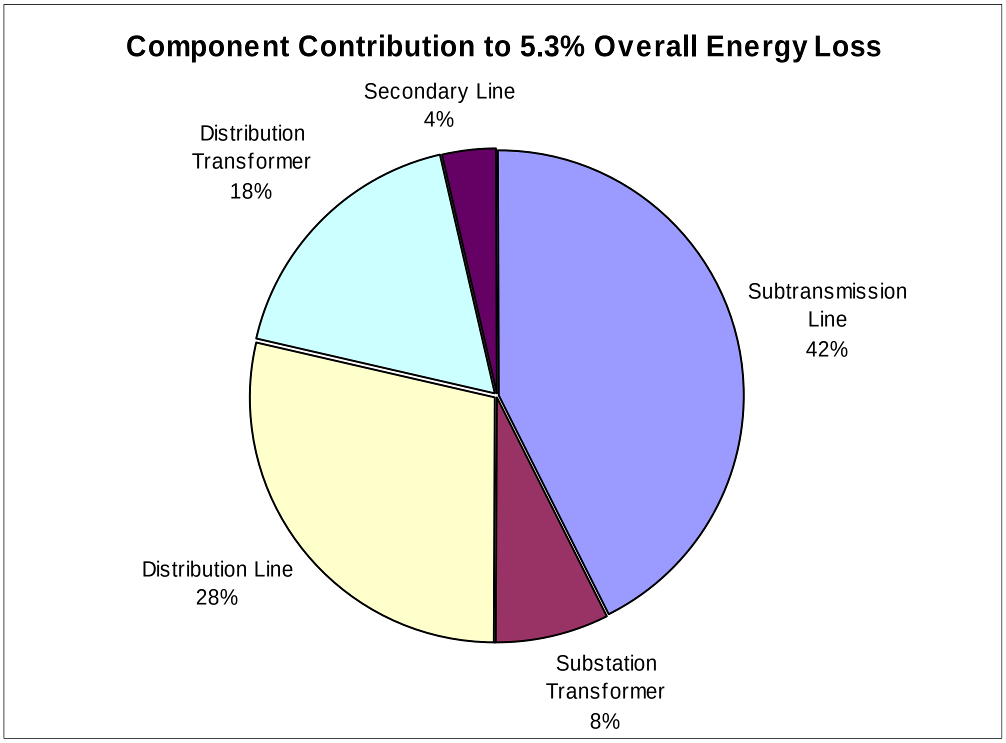
As part of the support for the rate application to the OEB, Hydro One requested a study of the energy losses on its electric power distribution system. The project included an overall assessment of technical energy losses on various components of the distribution system, an allocation of losses to three different rate classes resulting in distribution loss factors for each class, and development of a program to reduce energy losses. The original project report was filed in 2005.

In 2006, new data became available for load profiles. Some results from detailed circuit modeling of loss savings from capacitors and load balancing also became available. This report recalculates the energy losses based on the new information.

The high level system modeling using system component inventories, updated class load profiles and loading data from 2005 and 2004, has shown that the best estimate of the annual energy loss in Hydro One distribution systems is 5.3% of energy sales, with an outside range of 4.1 to 6.4% based on input parameter sensitivity modeling. The contribution of different system components to this total is shown in the pie chart on the following page.

The distribution system energy loss has been allocated to the major rate classes to produce several technical loss factors. The estimate for non-technical losses has been added to produce an estimate of the distribution loss factor (DLF). The supply facilities loss factor has then been added to produce an estimate of the Total Loss Factors (TLF). The comparison of these new TLFs with those that have been used previously is shown in the table on the following page. The changes are due to the improved load profile data.

The recommended loss management program for Hydro One is based on a combination of shunt capacitor installation and phase balancing. A program with an overall benefit to cost ratio of 2.2 to1 has been designed based on a combination of $5.1 million in capital spending on shunt capacitors, $1.3 million in O&M costs on phase balancing over the next two years. Hydro One Networks commenced work on this program in 2006. The benefits of changing out conductor and improving distribution transformer efficiency and sizing have been estimated and these areas are recommended for further detailed costing study by Hydro One.



Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

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1 CONCLUSIONS AND RECOMMENDATIONS

1.1 OVERALL TECHNICAL LOSS ESTIMATE

A high level computation in this 2007 study using the latest system component inventories, updated class load profiles and component loading data has shown that the best estimate of the annual energy technical loss on Hydro One distribution systems is 5.3% of energy sales, with an expected range of 4.1 to 6.4%.

The change in the estimated breakdown of loss by power system component is shown in the following table. The largest changes are in power and distribution transformer load losses, and distribution and secondary line losses. These changes are primarily caused by the change in load profiles used in the calculation.

Table 1 Estimated Energy Loss

Component	**2005 Study Estimated Loss as a Percent of Total Energy Sold**	**2007 Study Estimated Loss as a Percent of Total Energy Sold**
Subtransmission Lines	2.33	2.24
Power Transformers No Load	0.21	0.21
Power Transformers Load	0.12	0.19
Distribution Lines	1.18	1.49
Distribution Transformers No Load	0.78	0.78
Distribution Transformers Load	0.19	0.16
Secondary Lines	0.24	0.19
Total	5.05	5.26

1.2 TOTAL LOSS FACTORS

The change in Total Loss Factors (TLFs) calculated based on these technical losses are shown in the following table and compared to the previous TLF values used by Hydro One.

Table 2 Calculated Total Loss Factors

Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

1.3 TECHNICAL LOSS REDUCTION PROGRAM

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and the avoided costs for generation, transmission, and distribution based on the OEB's Total Resource Cost Guide. The costs and benefits of the program over the next two years have been included. The present value of the benefits for these programs has been calculated over twenty years. The overall benefit to cost ratio of the program is 2.2 to1. Hydro One Networks commenced work on this program in 2006.

Table 3 Loss Reduction Program Summary

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy and Demand Costs PV $M	Cost of Program $M	Profitability Index
PF Correction Capacitors - install cap banks on 278 feeders	9.8 *(53)**	8.7 *(52.9)*	5.1 *(10.3)*	1.7 *(4.2)*
Phase balancing - balance 314 circuits -2 years of a 6 year program	7.6 *(15)*	5.2 *(11.4)*	1.3 *(2.2)*	4.0 *(5.4)*

* Note: The values from the study filed in 2005 are shown in brackets and smaller font for comparison. The large change in the capacitor program is due to the change in assumed load profile reducing the number of circuits on which large capacitor banks could be installed. The large change in the phase balancing program is also due to a reduction in the estimated circuits that can achieve significant energy savings in the next two years.

1.4 REVIEW OF LOSS MODELING AND LOSS REDUCTION ANALYSIS

The detailed loss modeling techniques used by Hydro One have been reviewed and found to be appropriate.

The estimate of potential loss reduction on the Hydro One system has been revised to reflect the latest load profile information available.

The benefits of changing out conductor and improving distribution transformer efficiency and sizing have been estimated and these areas are recommended for further detailed costing study by Hydro One.

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy and Demand Costs PV $M
Conductor Change Out - 1 km of 8 circuits - 2 yeas of a ten year program	2.0	5.4
Transformer Sizing and Efficiency - normal replacements for two years	6.8	6.4

2 INTRODUCTION

In 2005 Kinectrics prepared a report on the annual energy losses on the Hydro One distribution system. In 2006 new data on the load profiles of the different customer classes and a few distribution circuits became available. Furthermore the results of detailed circuit modelling conducted by Hydro One on the reduction of losses through installation of capacitor banks and phase load balancing also became available. This report includes results of a recalculation of the energy losses and potential savings including the new information. All the other information on which the estimate of energy losses is based remains the same. The previous report filed in 2005 is included as Appendix A for convenience in making comparisons.

As well as recalculating the results of the previous report, this report presents the results of new analysis into the potential energy savings from reconductoring, and changing distribution transformer purchasing and loading procedures.

There were four major project tasks:

- Review Existing Methods of Loss Modeling and Loss Reduction Analysis
- Recalculate Capacitor and Phase Balancing Savings
- Estimate Savings of Improved Efficiency Distribution Transformers
- Estimate Savings of Conductor Replacement for Loss Reduction
- Review Cost Models for Loss Reduction

3 REVIEW EXISTING METHODS OF LOSS MODELING AND LOSS REDUCTION ANALYSIS

3.1 SUMMARY OF NEW INFORMATION

The new data on load profile that became available in 2006 consisted primarily of load profiles for a company wide aggregation of all customers within a specific customer class and the total for all classes. This aggregation of all customers together produces a smooth load profile that is representative of the entire Hydro One system and the heavier loaded transmission and subtransmission lines. This load profile is smoother than can be expected on distribution circuits. The most appropriate load and loss factors, based on the best available data, are shown in Table 4, along with the values used in the 2005 report for comparison.

The load profiles for secondary lines are based on data of specific load classes or groups of similar load classes. The load profile for each component is a combination of the profiles of all the customer classes that use that component weighted by the proportion of energy sold in a year to each of those classes. Two alternative load profiles are given for distribution lines, because the heavier loaded lines will have a smoother profile than the lightly loaded lines. Examples of both of the recommended load profiles for distribution lines have been found in the limited data available from a distribution station automation field trial. The power transformer load profiles are different for HONI transformers and customer transformers because of the different data for the load classes served by these two types of transformer.

Table 4 Recommended Load and Loss Factors

Component	2005		2007	
	Load Factor	Loss Factor	Load Factor	Loss Factor
Secondary Lines – Residential Rural	0.367	0.179	0.46	0.23
Secondary Lines – Residential Urban	0.367	0.179	0.48	0.25
Secondary Lines - Seasonal	0.165	0.076	0.40	0.18
Secondary Lines – Farms	0.510	0.303	0.43	0.22
Secondary Lines – General Service <5 MW	0.517	0.329	0.58	0.35
Distribution Transformers	0.422	0.226	0.40	0.175
Distribution Lines – Average	0.422	0.226	0.40	0.175
Distribution Lines – Heavy Loaded	0.422	0.226	0.56	0.33
Power Transformer – Customer	0.715	0.521	0.70	0.49
Power Transformer – HONI	0.715	0.521	0.40	0.175
Subtransmission Line	0.715	0.521	0.66	0.45

3.2 HYDRO ONE'S DETAILED CIRCUIT MODELING

Hydro One has conducted detailed modeling of distribution circuits to identify the circuits requiring load balancing and the optimal locations for installation of the capacitor banks and to confirm the savings estimated in the Kinectrics report in 2005. The result of detailed modeling on 240 circuits was provided for use in this project. From this detailed modeling, potential capacitor bank installations have been identified on 122 of the circuits with an average reduction in peak loss of 5.6 kW. Load balancing opportunities have been identified on 158 circuits with an average reduction in peak loss of 8.5 kW per circuit.

The majority of the recommended capacitor bank installations are 150 kVar. Comments by the technical staff doing the modeling indicate that the most frequent reasons that larger banks cannot be installed is that they would produce a leading power factor when the load is 30% of the peak or lower. Another common limitation is that the phase unbalance in Var flow limits the size of one phase of the bank. The unbalance in the Var flow is caused by unbalanced currents or unbalanced power factors.

The detailed modeling was conducted using a commercial software package (PSS ADEPT) to calculate the loss at peak load. Load can be balanced by moving single phase connections. Capacitors can then be added to reduce the loss. The optimal capacitor location is sometimes selected by the software program but often has to be chosen by trial and error. The loss at peak load is then converted to an energy loss by multiplying by a loss factor. The models are checked for potential voltage problems from the application of the capacitors.

The choice of loss factor has a major impact on the estimate of energy saved. The peak power savings are estimated quite accurately by the software, limited only by the accuracy of the input data. Suspicious input data have been confirmed by requests for field verifications. However, the most appropriate value for the loss factor is not well known. It depends on the load profile of the circuit, that is on how the current varies from hour to hour over the entire year.

A review of the individual circuit models and the comments of the analysis technicians, has found that the modelling techniques for the detailed circuit models are appropriate.

Examination of the model files and comments by the modelers indicates the following modeling techniques were used:

1. A power factor of 0.95 is assumed for all loads (0.9 for summer peaking)
2. A loading of measured peak+10% is assumed
3. Loads are lumped at the ends of most lines
4. Phase balancing is assumed to have been completed
5. The loss at peak load is calculated with PSS ADEPT
6. Capacitor is sized to produce no leading PF at 30% of peak load
7. Energy loss is calculated from loss at peak with a loss factor of 0.33 at first, now 0.23 to match the value used by Kinectrics in the 2005 report.

The techniques listed above were evaluated by Kinectrics and the results of the detailed modeling were compared to the 2005 high level analysis by Kinectrics.

Technique 1 is reasonable. The power factors of the loads in the models are a large source of uncertainty. The power factor is known for a few of the large loads, but for most loads it is assumed to be 0.95. Although the best information available indicates that this is the overall average power factor for Hydro One distribution circuits, there is a wide range. Assuming 0.95 will limit the size of capacitor bank that is recommended for circuits whose actual power factor is less. This will not produce uncertainty in the estimated energy savings, since the smaller bank will actually be installed. On circuits whose actual power factor is 0.99 there may be high voltage problems after the capacitor bank is installed. The model will not predict this voltage problem because it is assuming a lower power factor. This will produce some error in the estimate of energy savings, since the capacitors on these circuits will need to be reduced in size or removed.

Technique 2 is reasonable. It accounts for the measurement not necessarily being on peak day.

Technique 3 is reasonable. It will over estimate loss for single phase lines by a factor of 1.5, but 80% of loss is on three phase lines. It will not significantly over estimate the loss savings on three phase lines because only a small fraction of the load is distributed along the line. It will not over estimate the energy savings because most capacitors are installed on three phase lines, producing no saving on single phase lines.

The loads in the model distributed according to the connected kVA which is known for each switch. The loads are then scaled so that the current at the station matches the measured data. The larger loads that have individual load data available are not scaled. This is a reasonable procedure.

Technique 4 is reasonable, but Kinectrics previous estimate did not assume this. The effect of applying this to the Kinectrics estimate depends on the amount of final imbalance. If perfect balance were achieved, the Kinectrics estimate of loss savings from capacitors would be decreased by 33%. In the studied circuits (240) the final imbalance is 5%. At this imbalance the Kinectrics loss savings estimate would be reduced by 30%.

Technique 5 is reasonable.

Technique 6 is reasonable but uncertain. The Barrie field trial data shows minimum load ranging from 0.16 to 0.61 but most are within 0.3 to 0.4. Based on this data the detailed study assumption of 0.3 is probably best.

Technique 7: the loss factor is probably reasonable. The major source of uncertainty in the estimate of energy savings from the detailed modeling is the loss factor used to calculate the annual energy saving from the peak power saving calculated by the detailed model. The loss factor varies with different load profiles on different circuits. Measured data is available on only a few circuits. It indicates that the annual load factor can vary from 0.33 to 0.63 and the corresponding loss factor can vary from 0.12 to 0.41 (data from the Barrie Automation Field Trial at Midhurst, Angus, and Drayton DSs). The average was a load factor of 0.5 and a loss factor of 0.27.

The previous load profile used by Kinectrics was built up from customer load profiles, with no smoothing due to diversity and had a load factor of 0.49 and a loss factor of 0.23. It produced the correct amount of energy sold when used in the total system model, with little alteration of the peak loading on the circuit. It is therefore appropriate for a “typical” circuit. However, capacitors are used only on heavier loaded circuits which will have a smoother profile.

The conclusion is that there is some uncertainty regarding the most appropriate loss factor to use. The loss factor of 0.23 used previously is probably too low. It could be as high as 0.41 or more. A value of 0.33, which was used originally in the detailed studies, is recommended for the heavier loaded circuits where capacitor banks are installed.

3.3 METHOD OF SELECTING CIRCUITS FOR DETAILED ANALYSIS

Hydro One’s present method of identifying lines for analysis is to select the lines with the largest imbalance, that also meet a minimum current level criteria and to select the circuits with the largest currents. This method has been used because each circuit is analyzed for both imbalance and capacitor bank application. Some of the circuits analyzed are therefore not expected to require a capacitor bank since they are being analyzed primarily for imbalance.

To select the most likely circuits for capacitor bank application, it should be the circuits with the worst power factors, the highest minimum loads, and the longest three phase lines with the least branching; but the circuits with these characteristics are not known. These circuits could be indicated by using the circuits with the largest minimum loads. These are also not known. They could also be indicated by the circuits with the largest loads in MW or MVA. This is the best, feasible approach given the presently available data. Using the peak power level is a slight improvement on using current to select circuits to study since the higher voltage lines will be able to accept a capacitor bank at a lower current level than the lower voltage lines. Alternatively a different minimum current level could be used for different voltages.

4 RECALCULATION OF OVERALL TECHNICAL LOSS ESTIMATE

Based on the new information on load profiles the overall technical loss estimate has been recalculated in 2007. The calculation method remained the same as earlier estimates in 2005 and is described in Appendix A. The results of the recalculation are shown in Table 5. The previous estimates are shown in smaller font and italics.

Table 5 Summary of Loss Estimation Results

	Peak Power (delivered by component) (MW)	Annual Energy (delivered by component) (GW-h)	Power Loss at Peak (MW)	Power Loss at Peak (% of total)	Annual Energy Loss (GW-hr)	Annual Energy Loss (% of total)	Annual Energy Loss as % of total energy sold
Subtransmission Line	8,950 *8,600*	34,100 *35,000*	220 *200*	30 *34*	877 *913*	43 *46*	2.24 *2.33*
Power Transformer No Load	5,060 *3,270*	19,800 *20,500*	9.4 *9*	1.3 *2*	82 *82*	4.0 *4*	0.21 *0.21*
Power Transformer Load	5,060 *3,270*	19,800 *20,500*	24 *11*	3 *2*	73 *48*	3.5 *2*	0.19 *0.12*
Distribution Line	4,710 *4,530*	18,900 *18,750*	382 *233*	52 *40*	585 *461*	28 *23*	1.49 *1.18*
Distribution Transformer No Load	3,780 *4,290*	16,900 *16,900*	35 *35*	4.7 *6*	304 *304*	15 *15*	0.78 *0.78*
Distribution Transformer Load	3,780 *4,290*	16,900 *16,900*	29 *37*	3.9 *6*	63 *74*	3.1 *4*	0.16 *0.19*
Secondary Line	3,480 *4,290*	16,800 *16,800*	37 *62*	5.1 *11*	76 *93*	3.7 *5*	0.19 *0.24*
Totals			740 *587*	100 *100*	2,060 *1,976*	100 *100*	5.26 *5.05*

The total annual energy delivered by the subtransmission lines is less than the total purchased from the transmission grid (39,165 GWh) because some of the energy purchased flows through high voltage substations supplied directly from 115 kV. Similarly the total energy delivered by distribution lines is less than the energy delivered by distribution transformers and secondary lines plus the primary customers because some of those distribution transformers are directly connected to 27.6 kV subtransmission lines in south west Ontario.

5 RECALCULATION OF TOTAL LOSS FACTORS

The method for calculation of the total loss factors (TLFs) has not changed from the previous 2005 computation and is described in Appendix A.

The data for the total energy sales to each customer class was 19,089 GWh to embedded LDC and Subtransmission, 3,249 GWh to primary customers (considered to be three phase farm, three phase general service and acquired large users) and 16,827 GWh to secondary customers. The total energy of 39,165 GWh is therefore sold 48.7% to embedded LDC and subtransmission, 8.3% to primary customers and 43% to secondary customers.

The method will be illustrated with an example for primary customers. The total annual energy loss on subtransmission lines and power transformers (877 +82+73 from Table 5) is 8.3% allocated to primary customers. Since only primary and secondary customers use the distribution lines that loss (585 from Table 5) is allocated to primary customers at 16.2% (3249/(3249+16827). The allocation of loss is then 180 GWh (0.083 x (877+82+73)+0.162 x 585). The technical losses are then 5.6% (180/3249). Adding 1.2% for non-technical losses gives a distribution loss factor (DLF) of 6.8%. Adding 0.6% for the supply facilities gives a total loss factor (TLF) of 7.4%.

This TLF would apply to primary customers whose energy meter is on the high voltage side of the customer's transformer. If the energy meter is actually on the low voltage side of the customer transformer then the TLF must be increased by the average distribution transformer loss of 0.94% of energy sold (.78+.16 from the last column of Table 5). This would increase the TLF for these customers from 7.4% to 8.3%.

Table 6 shows the effect of the recalculation based on the new information.

Table 6 Comparison of TLFs

Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

The 1.2% estimate for non-technical losses is the same figure used in the previously filed report in 2005. It is applied to all customer classes evenly because all customer classes contribute to non-technical losses. For customers supplied at high voltage this can be in the form of inadvertent blowing of a potential transformer fuse or in the form of meter tampering. At lower voltages meter tampering and meter by-pass both occur.

6 RECALCULATION OF CAPACITOR AND PHASE BALANCING SAVINGS

In 2005 Kinectrics estimated the potential savings from the installation of capacitor banks and from balancing phase currents on Hydro One distribution circuits. This estimate was made using the best information available at the time. Since that time Hydro One has obtained more detailed load profile information and performed detailed modeling on 482 circuits. This detailed modeling has provided more information that can be used to refine the estimate of the total potential energy savings. The most significant new information for capacitor savings studies is that 28% of the circuits already have optimally sized capacitor banks installed.

In addition to the new customer class load profiles provided by Hydro One, Kinectrics has analyzed load profile data for a sample of Hydro One distribution circuits. This analysis combined with the new customer class load profiles has provided new information that suggests that the load profile used by Kinectrics for distribution lines in the previous study, may not have been representative of all Hydro One circuits.

The results of the detailed individual circuit modelling did not confirm the estimated savings described in the Kinectrics report from 2005. A comparison is shown in the following table.

Table 7 Comparison of Potential Savings Estimates

Saving type	Detailed Hydro One Models	Kinectrics 2005 Report Estimate
Load Balancing Annual Energy Savings (GWh)	5.9	15
Capacitor Annual Energy Savings (GWh)	9.6	53

It has been determined that several factors lead to the differences in the preliminary estimates of energy savings and the estimates in the detailed modeling including:

- 28% of circuits already having capacitors installed
- Assumed load profiles (affects the size of the capacitor banks recommended, and energy saved per kW peak loss saved)
- Assumed phase balance
- Number of circuits balanced

The largest difference in the capacitor savings estimate is the size of the recommended capacitor banks. A major source of this difference is that the Kinectrics estimate included all the heavily loaded circuits. When the 2005 Kinectrics estimate was made, there was no solid indication of how many circuits, or which ones, had capacitors installed; and it was thought that many of the previously existing capacitor banks had been removed, leaving very few in service.

A review has been made of the results of the detailed modeling on 100 circuits that were also part of the Kinectrics preliminary estimate. Comments of the technical staff doing the detailed modeling indicate that at least 28% of these circuits already had capacitor banks installed and could not handle more. Another 42% showed minimal potential savings for a variety of reasons, including severe VAr imbalance, very short lines, or very branched topology.

The detailed modeling has provided this new information that was not available at the time of the Kinectrics estimate. It is still not known how representative the 28% and 42% figures are of all the circuits at Hydro One. It is possible that if the 28% represents the 28% most heavily loaded circuits, which would not be surprising since these circuits would benefit the most from capacitors for both voltage support and loss reduction. If this is correct then the Kinectrics estimate should be lowered by removing some or all of the heavily loaded circuits.

Another source of the difference in the estimates is in different assumptions about load profile. The Kinectrics estimate assumed that capacitor banks would be sized to balance the Var flow at a load of 50% of peak. This is assuming a relatively flat load profile. The detailed modeling was done using a 30% of peak criteria. The effect of the different assumption is that the detailed modeling will size a capacitor bank at 60% (30/50) of the value in the Kinectrics estimate. This means that where Kinectrics would use a 300 kVar capacitor the detailed modeling procedure would only use 150 kVar. Very little load profile data is available to test these assumptions. Examples of both lower limits (50% and 30%) are in the available data.

The detailed modeling of savings from phase balancing has revealed that there is very little correlation between the initial unbalance and the amount of saving possible. A similar lack of correlation exists with load current, and even the two combined. This is caused by the large number of confounding factors that are unknown except in a detailed study of a specific circuit. These confounding factors include line branching and load distribution. Since the previous Kinectrics estimates were based on assumptions that the savings would be dependent on unbalance and current, a new methodology of estimating savings from phase balancing was required and will be developed in section 6.2.

6.1 RECALCULATION OF ENERGY SAVINGS FROM CAPACITOR INSTALLATION

The changes in the modeling assumptions for estimating the annual energy savings from the installation of capacitor banks are summarized in Table 8. The assumed load profile used in the new estimate is for heavily loaded distribution lines.

Table 8 Changes to Assumptions for Kinectrics' 2005 Estimate in Kinectrics' 2007 Estimate

	Study Filed in 2005	2007 Study Revised Estimate
Circuits with existing Capacitors	0%	28%
Load Profile – Load Factor	0.49	0.56
Load Profile – Loss Factor	0.23	0.33
Phase Balance	Uncorrected	Corrected
Minimum load (% of peak)	50%	30%

Using this new information the estimate of potential savings from capacitor bank installation has been revised.

The new overall analysis predicts 0 circuits for 600 kVar (assuming the 11 circuits that would take this large a capacitor already have them installed) 12 circuits for 450 kVar saving 1.3 GWh, 40 circuits with 300 kVar saving 2.5 GWh and 226 circuits with 150 kVar saving 6.7 GWh.

Using the PV of the savings calculated in the previous Kinectrics report (not including environmental costs) and the estimated cost of capacitor banks, the cost information shown in the final three column of Table 9 have been calculated. A $1 million cost for detailed circuit modeling to size individual capacitor banks on specific circuits has been divided proportionally among the bank sizes.

Table 9 2007 Revised Estimate of Potential Energy Savings from Capacitor Bank Installation

Capacitor Bank Size (kVar)	Number of Circuits	Energy Saved (GWh)	$ Saved (k$)	$ Cost (k$)	Profitability Index
150	226	5.9	5,263	4,080	1.3
300	40	2.5	2,230	762	2.9
450	12	1.4	1,250	239	5.2
600	0	0	0	0	
Total	278	9.8	8,743	5,081	1.7

The uncertainty in the estimate of energy savings is quite high. The loss factor uncertainty can vary the estimated savings by 30% either higher or lower. Other sources of uncertainty are insignificant in comparison.

6.2 RECALCULATION OF ENERGY SAVINGS FROM PHASE BALANCING

The new method for estimating the total potential savings from load balancing has been based upon the results of the detailed studies done to date. The detailed studies have analyzed 482 circuits and found savings from load balancing in 256 circuits with an average savings of 8.2 kW at peak load. Circuit loading data bases show that there are at least 250 circuits in the Hydro One system with more than 37% unbalance and more than 50 amps of load current. These are likely candidates for load balancing. Only 58 of these circuits have been modelled in the detailed study. These 58 circuits averaged a savings of 9.6 kW at peak.

If the new peakier load profile, used in the capacitor savings estimate, is also applied to this peak saving then the annual savings per circuit are estimated to be 24.2 MWh per circuit balanced. Using the PV of the savings calculated in the previous Kinectrics report (not including environmental costs) this would result in a total savings of $16,450 per circuit balanced. Compared to an estimated cost of $3,000 to balance the circuit and $955 to do the detailed modeling, this work would have a profitability index of 4.0.

The total number of circuits on which the losses can be improved by balancing the phase currents is not known and cannot be accurately predicted because it would require detailed modelling of all circuits. In the completed detailed modelling of 482 circuits, the total savings has been calculated to be 5.9 GWh. The latest circuit loading data base has 750 circuit with significant phase unbalance and significant load current (>20% unbalance and >50 Amps). Planned circuit modelling over the next 6 years will identify which circuits will benefit most from load balancing.

If the results on the circuits modelled to date are extrapolated linearly then the total estimated savings would be at least an additional 4.9 GWh of savings in addition to the 5.9 GWh on the circuits already modelled, for a total estimated energy saving of 10.8 GWh per year. The additional 4.9 GWH is assuming only the 192 circuits with the worst balances (>37%) but not yet modelled in detail will result in significant energy savings. This is a conservative estimate since many of the circuits with a significant imbalance but less than 37%, will be modelled and found to have potential savings as has been the case in the circuits already modelled in detail.

7 ESTIMATION OF SAVINGS FROM IMPROVED EFFICIENCY DISTRIBUTION TRANSFORMERS

Distribution transformers are a significant source of energy loss. This loss can be minimized by the design of the transformer and by carefully planning the loading of the transformer.

The design of the transformer includes many parameters that can be adjusted to reduce losses including: core size and material which affect the constant no-load loss and conductor size and material that affect the load loss, which varies. The losses inherent in the transformer design can be adjusted by the "cost of losses formula" that is used in the tendering document in the transformer purchasing process. The formula adds to the purchase price the expected present value of both no-load and load losses over the life of the transformer, so that different bids by manufacturers can be compared on a total cost of ownership basis. This process produces a transformer design that minimizes the life time cost, but does not minimize losses.

Kinectrics has recently recommended that Hydro One change the cost of losses formula so that it reflects the OEB approved avoided cost of losses for evaluation of conservation and demand side management programs. Separate values for rural and urban transformers are shown in Table 11 because the rural transformers serve fewer customers and therefore tend to be lightly loaded and their overall efficiency is thus more dependent on no-load losses. The actual cost of losses formula is :

$$TOC = CAPCOST + CNLL \times NLL + CLL \times LL$$

Where:

TOC	is the total cost of ownership ($)
CAPCOST	is the capital cost of the transformer ($)
CNLL	is the cost of no load losses ($/W)
NLL	is the no-load loss of the transformer (W)
CLL	is the cost of load losses ($/W)
LL	is the load loss of the transformer at rated load (W)

Table 10 Transformer Purchasing Cost of Losses Formula

Application	Loss Type	1997 ($/W)	New ($/W)
Rural	No-load	5.2	15.06
Rural	Load	0.9	2.75
Urban	No-load	7.4	15.06
Urban	Load	3.9	8.6

The energy savings from the change to the "new" formula depend on the actual loading of the individual transformers, and the effects of reducing each type of loss on the capital cost of each manufacturer's transformer design.

As an example, in a 50 kVA single phase pad mount, an amorphous steel core could reduce the no load losses by about 30% or 31.5W but at a cost of about $200 (ref DOE study). This is 6.3$/W which would lower the total ownership cost under the new cost of losses formula but raise it under the 1997 formula. The new formula will therefore allow for the use of amorphous cores, reducing no load losses by 30%.

Considering load losses, the resistance of copper wire is 36% less than similar size aluminum wire so its losses are 36% less, however it costs more. This is partially mitigated by copper windings needing a smaller, less expensive core because core opening is smaller for the same ampacity of winding. As an example (Ref DOE study) consider a 50 kVA padmount with aluminum windings which has a core cost of $275 and winding cost of $116 and compare with a transformer with copper windings at $246 core cost and $216 winding cost. The reduction of 36% in losses (239W) comes with a price increase of $71 or 0.3$/W. In this example case both versions of the cost of losses formula will result in the use of copper windings. The larger CLL value will encourage the use of larger conductors in the winding to reduce load losses, until this is balanced by the increase in capital cost of the copper used and the larger core required by the larger windings, and the increased no load loss of the larger core.

A reasonable expectation may be that the load losses will be reduced in proportion to the amount of capital money (increase in capital cost) that the manufacturer can spend on them. The new loss cost formula would give the manufacturer twice as much capital cost to spend on reducing load losses of urban transformers and three times as much for rural, compared to the old formulas. Weighting these by the proportion of urban and rural customers at Hydro One, this could result in a reduction in load losses by a factor of 0.51.

The overall effect of the recommended cost of losses formula is therefore expected to be a reduction of 30% in the no load losses and a reduction of 50% in the load losses. Using the total system no load and load loss values from Table 6 this would be a savings of 91 GW-h and 31 GW-h per year, when all transformers on the system have been replaced.

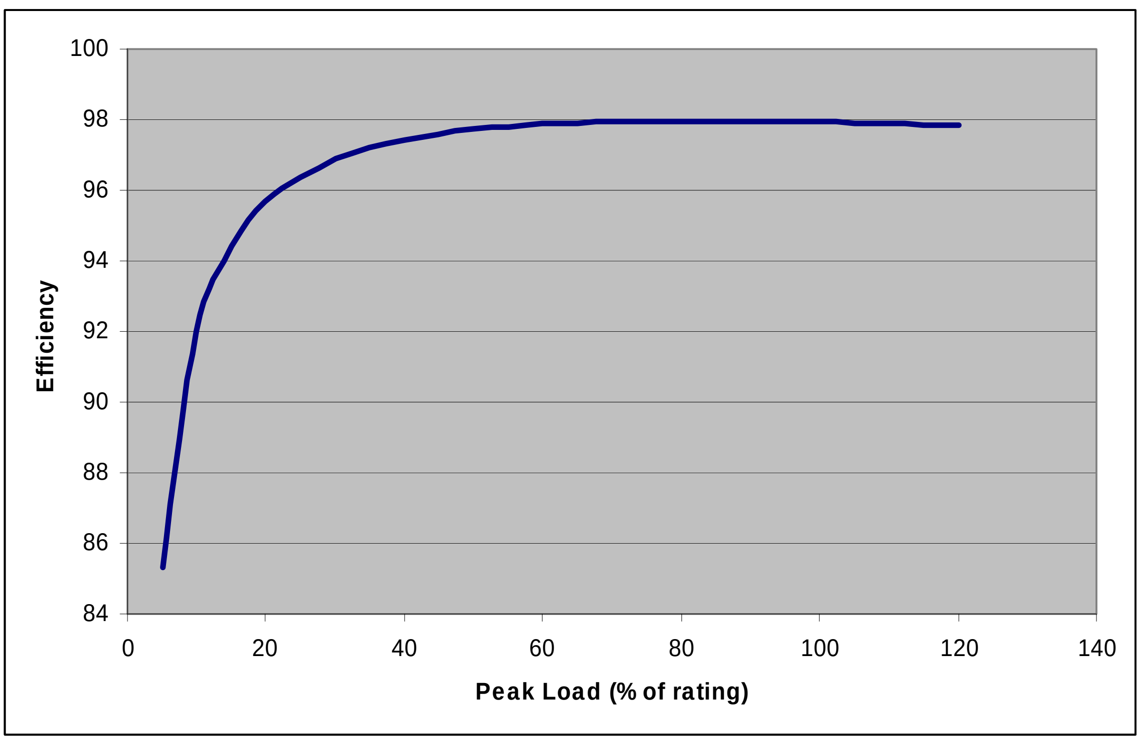
No matter what cost of losses formula is used in transformer purchasing specifications, the actual losses that occur will depend on how the transformer is loaded. Most transformers are designed for maximum efficiency at a constant 50% load. A previous study (Ref 2) found that on average Hydro One distribution transformers where loaded between 20 and 40% at peak load. The reasons for this are complex. Although the cost of losses would be reduced by using smaller transformers, the cost of inventory for stocking more sizes of transformers would be higher and partially off set the cost reduction in losses. The cost of transformer change outs when load grows unexpectedly, such as the construction of another house nearby, would also increase.

Independent of these non-technical considerations, it is necessary to accurately predict what the peak load will be on a transformer for any new load. This is done by considering the type of loads expected and the diversity of the loads. Load diversity is the reduction in the actual peak power drawn by the load below the sum of the peak power of the individual loads. There are two processes at Hydro One at the present time for sizing transformers based on type of load and load diversity. The 1992 Overhead Line Design Standard uses a procedure based on a table of “unit values” which are selected for each load on the transformer and then the transformer is sized on a separate table of total unit values and transformer kVA size. The diversity is taken into account in the construction of the second table, where the kVA/unit value varies from 10 to 1.9. Although no background information is given in the standard, one unit value appears to be equivalent to about 3 kW of load.

The Underground Line Design Standard has a different procedure for sizing pad mount transformers based on a diversity curve. Modifications to this procedure have recently been made by Kinectrics to bring the 1973 curves up to date. If the recommendations are adopted the recommended kVA for a single house will be reduced and larger load diversity will be assumed. Both of these will result in smaller recommended transformer sizes and increased loading, but the difference is typically 20% which will not increase the average peak load to 50% of rating.

A typical relationship between peak load and efficiency is shown in Figure 1. Notice that the realistic load profiles used in the calculation of Figure 1 (Load factor 0.49, loss factor = 0.23) make the maximum efficiency occur at a peak load of 80% of rating. The same transformer at a steady load will give a maximum efficiency at 50% of rating. Loading this transformer (25 kVA pole mount, single phase, 8.32/4.8 kV, NLL=0.26%, LL=1.71%) at 30% results in an efficiency of 96.9%, which means 3.1% of the energy carried is lost. Increasing this by 20% to 36% loading would only increase the efficiency to 97.2%. The expected savings in annual losses due to using the new diversity charts is estimated to be 9.7% of the present load loss. Using the present load loss from Table 5 this would be a savings of 7 GW-h.

Figure 1 Distribution Transformer Efficiency as a Function of Loading



Note: Efficiency has been defined as the energy output expressed as a percentage of the input energy .

The small overall savings in losses created by purchasing more efficient transformers and loading them appropriately is therefore estimated to be 91+37+7 = 135 GW-h per year. This is 36% of the 367 GW-h lost now in distribution transformers. It is a substantial saving but it can only be achieved by replacing all distribution transformers. Since this is a major investment, in the order of $900 million, it can only be done as the transformers reach their end of life over the next 40 years. The estimated savings over 20 years if all were replaced in the first year are only $119 million for a profitability of 0.13. If the transformers are replaced as they wear out then there are no additional costs to saving 3.4 GW-h more each year. This would be 67 GW-h after 20 years and a present value of the savings would be $28 million.

This cost analysis has been made on the basis of an estimate of the direct cost of the transformer. This direct cost cannot be accurately predicted because the cost of a transformer is based on a competitive tendering process. The price of efficient transformers depends on the cost of labour and materials at the time on the order and also on the number of other utilities specifying a similar transformer. There is a large price penalty for buying transformers that are not standard products and mass produced for many other buyers.

In addition to the direct costs of the transformer there are other costs associated with changing to more efficient transformers, particularly amorphous core transformers which have lower no-load losses. The amorphous steel cores saturate at lower levels of magnetic flux, and therefore the cores must be larger. This makes the overall transformer significantly larger and heavier. When a transformer is replaced an assessment must be made of the condition of the wood pole on which it is mounted. If the pole strength is not adequate then a new pole must be installed, considerably increasing the cost of the transformer replacement. This situation would happen more frequently if heavier transformers are used.

Other sources of costs in switching to more efficient transformers include, writing new specifications and purchasing documents, new work procedures to handle the heavier transformers, increased stocking, warehousing and transportation charges.

Kinectrics has not been able to include all of the costs in the estimate since they are dependent on the internal business processes at Hydro One and on the market for distribution transformers. It is recommended that Hydro One conduct an internal study of the cost of changing to more efficient transformers and compare the costs with the benefits presented in this report.

8 ESTIMATION OF SAVINGS FROM CONDUCTOR REPLACEMENT FOR LOSS REDUCTION

Distribution line losses can be reduced by replacing small conductors with larger ones. This is particularly cost effective if a larger conductor is chosen when the line is built, because then there are fewer extra costs other than the cost of conductor. However, often larger conductors require stronger poles and more guying which increase the costs. The following analysis calculates when changing out conductor on an existing line can be cost effective.

The conductor costs, obtained from a manufacturer's website (Southwire) in October 2006 are shown in the following table.

Table 11 Conductor Data

Conductor	Cost ($/conductor- km)	Resistance (ohms/km)	Ampacity (Amps)
#2 ACSR	840	0.8501	200
1/0 ACSR	1,260	0.5351	275
3/0 ACSR	1,990	0.3363	365
336 MCM ASC	3,660	0.1683	565
556 MCM ASC	5,660	0.1017	775

The resistance values are from Hydro One Line Design Standard 1992. The ampacities are summer values from the same source. Winter ampacities are approximately 22% higher.

The installed cost of stringing new conductors has been estimated by Hydro One, based on recent projects, at between $200,000 and $250,000 per km of three phase line. The costs are high because the line being reconductored is usually the first km of the circuit, close to the substation, where the poles carry more than one circuit and require replacement to have adequate mechanical strength to handle the larger conductors.

The cost of poles and hardware on a new three phase distribution line has been estimated at 35$/m (Ref 4) or $38/m adjusted to 2007 dollars. The extra cost of using larger poles, smaller pole spacing and heavier guying has been estimated as 18 $/m for medium conductor sizes (556, 750) and 30$/m for the largest (1033) in new construction. For retrofit situations where stronger poles and guys are required the full 38+18(or 30)=$56(68)/m cost would apply. The conductors themselves would cost another $19/m (5.66 x 3 + 1.9) or $26/m for the largest size. The total estimated cost for new construction would then be $75/m (56+19) or $94/m (68+26). This is an additional $19m for changing the new design to a larger conductor. When compared with the $225/m for reconductoring an existing line, it is clear that although using larger conductors in new construction might often be cost effective, retrofitting to larger construction can be expected to be cost effective in very few cases.

In the energy loss calculations, the resistance of the conductor has been increased at higher loading levels because the resistance increases at higher temperatures. The adjustment factors are shown in the following table (Ref 5). The annual load profile for Hydro One was used to calculate the fraction of the year at each conductor temperature assuming the annual peak load was at the thermal capacity of the line (90 ºC). For conductors loaded at less than the thermal capacity at peak, the resistance was adjusted a lowered amount, in proportion to the fraction of the peak load squared. In the final analysis the temperature correction was only a few percent of total ownership cost if peak currents were less than 200 amps. It could be as high as 20% at 500 amps.

Table 12 Conductor Resistance Temperature Adjustment

Temperature (ºC)	Multiplying Factor	Fraction of Time
0	0.92	0
10	0.96	0
20	1	0
30	1.04	.008
40	1.08	.09
50	1.12	.28
60	1.16	.45
70	1.20	.15
80	1.24	.02
90	1.28	.002

The costs of losses over a twenty year planning period were added to the capital cost to obtain a total ownership cost. The cost of losses in each year was calculated using the energy and power costs provided by the OEB (Ref 6). The expected conductor life is greater than forty years. If a forty year planning period had been used the present value of the savings would be 25% higher. If a ten year planning period is used the values would be 34% lower.

New load profile data (8760 hrs) was obtained in 2006 and an overall load factor of 0.66 and loss factor of 0.45 was calculated from these data. Since the load profile data was from the entire load of Hydro One, these profiles are suitable to apply to subtransmission lines but not distribution lines. Distribution lines have less load diversity and therefore “peakier” load profiles. A load factor of 0.56 and loss factor of 0.33 have been estimated for heavily loaded distribution lines. These are the same values used in the calculation of energy savings from capacitor banks. Using the lower values reduces the total ownership costs by 20% at 500 amps and 10% at 200 amps.

In the figures of total ownership cost shown below, the load growth is assumed to be 1% per year and the financial discount rate is 9.3%. The total ownership cost is the capital cost plus the present value of the expected cost of the losses.

Figure 2 Total Ownership Cost at Low Current Levels

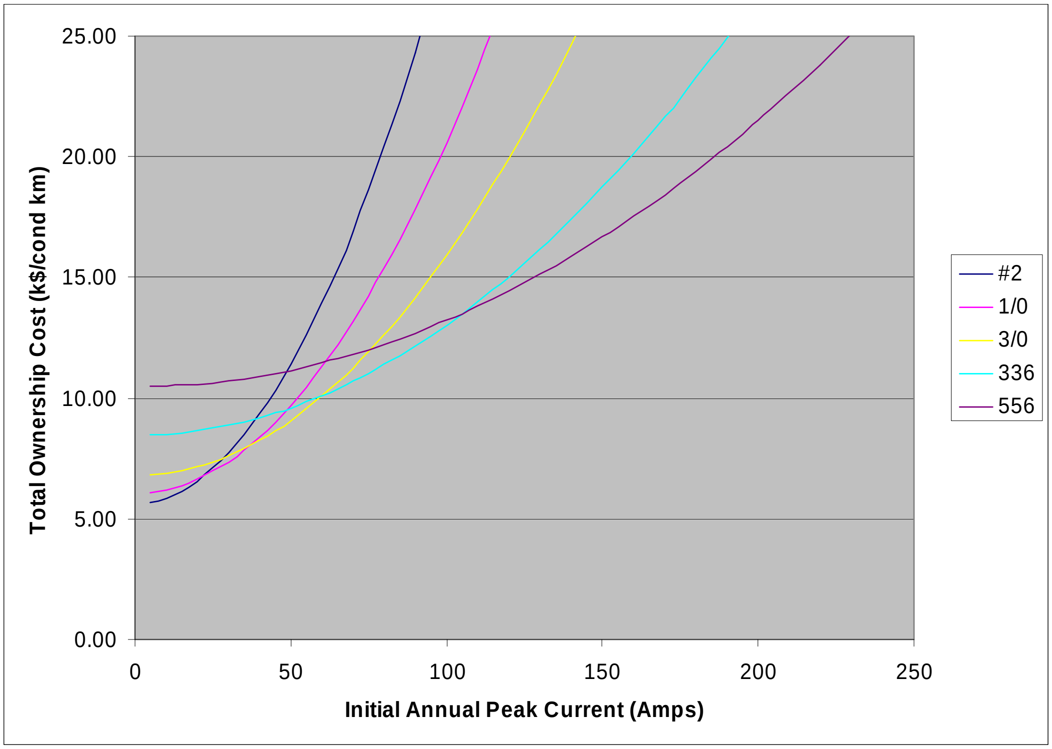


Figure 3 Total Ownership Cost at High Current Levels

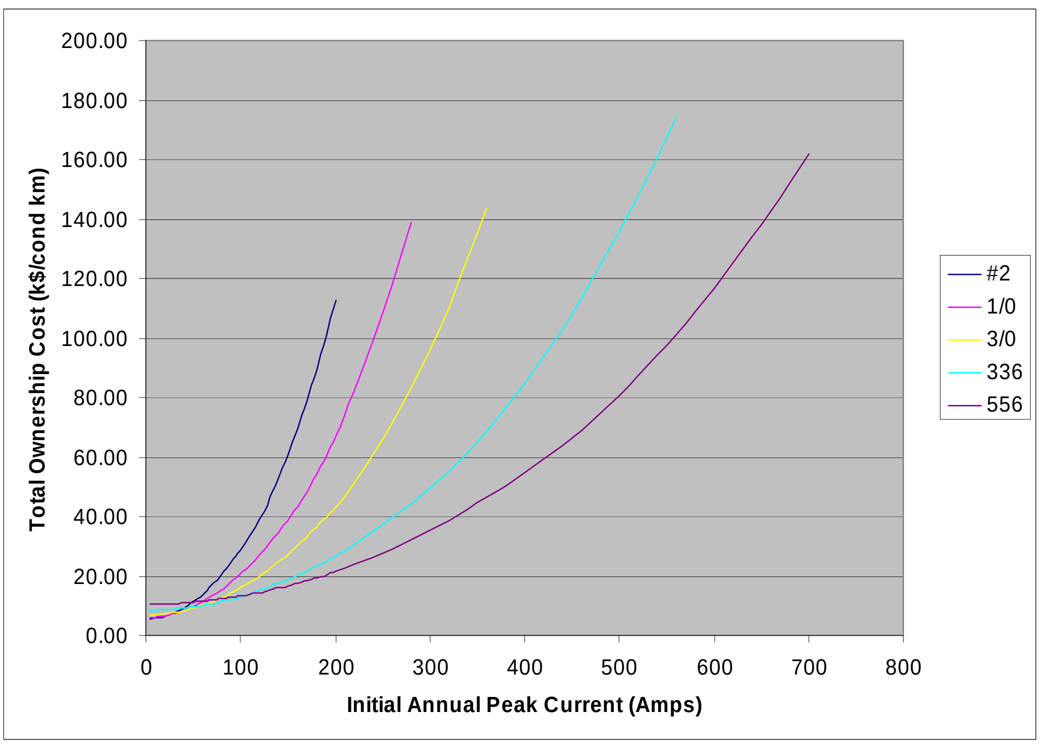


Figure 2 illustrates that the cost of losses dominates over the capital cost of the conductor at any significant load. For example the 336 conductor has an installed capital cost of $8.5/m (the vertical intercept) and even at a peak load of 34% of rating (190 amps) the total ownership cost is triple at $25/m. This means that even in urban areas where the voltage drop is not limiting, large conductors should be used to minimize the total ownership cost. At the present time the largest conductor routinely used at Hydro One, 556 MCM ASC, should be used whenever the expected peak current is greater than 100 amps. However, if larger poles and guys are required, increasing capital cost for the larger conductor by $10/conductor–m in new construction, then the lower load limit for 556 conductor increases from 100 amps to 230 amps.

In order for a retrofit change in conductor size to be cost effective, the reduction in the total ownership cost in Figure 2 or 3 (vertical distance between the curves) must be greater than the reconductoring cost. Using the reconductoring cost for Hydro One of $225/m of line gives a breakeven point of $75/conductor km.

A single step in conductor size was found to never be cost effective.

Figure 4 Profitability of Conductor Change Out to Reduce Losses

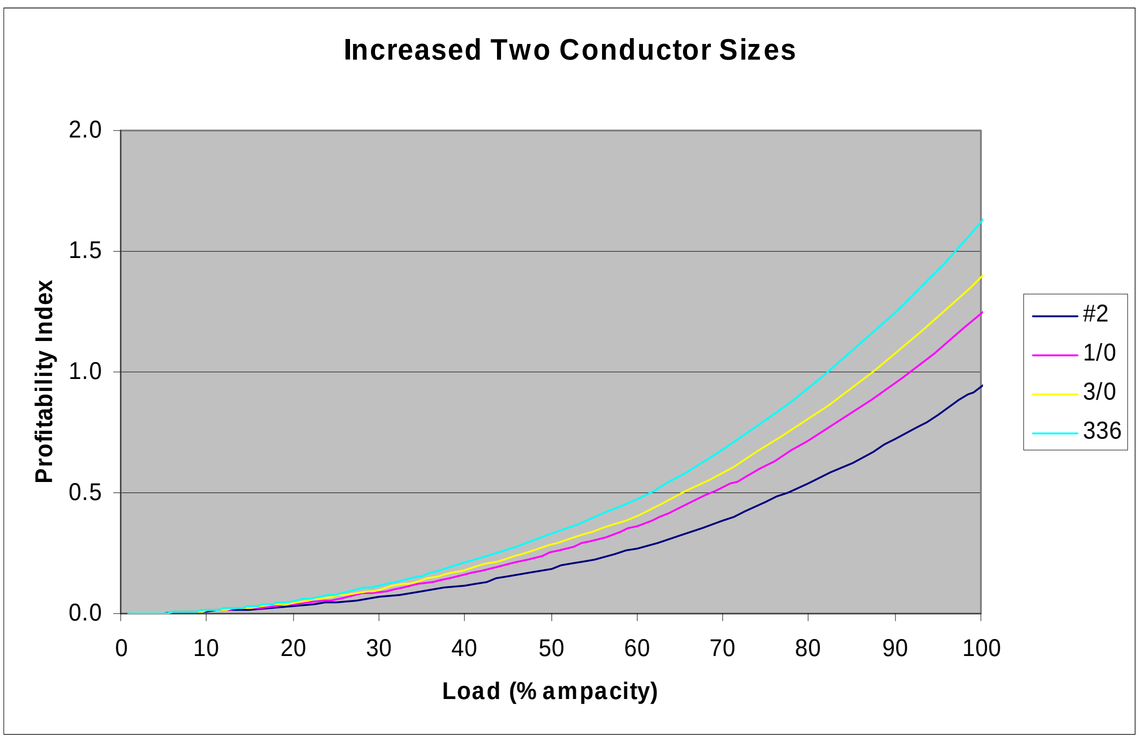


Figure 4 shows the profitability index (ratio of the present value of savings to the cost of reconductoring) of replacing a conductor with one two sizes larger in the standard Hydro One conductor set, as a function of the initial load on the smaller conductor. A reasonable decision criterion is to use a profitability of at least 1.5 to indicate that a line should be reconductored. This gives some room for error in the estimate and still ensures that the project is profitable. In Figure 4 the criterion is met only for 336 conductor when the peak load is more than 95% of the ampacity of the line. The curve was calculated with a twenty year study period. If a forty year period is preferred then a criteria of a profitability ratio greater than 1.2 is equivalent. This would give the same % loading as a profitability ratio of 1.5 calculated for a forty year period. If a ten year period is preferred then the criteria should be a profitability ratio of at least 2.2 and no conductor would ever be replaced as a cost effective way to reduce losses. A single step in conductor size was never cost effective.

The values in the figures were calculated using the “peakier” load profile of distribution lines. If the smoother load profile of subtransmission lines is used then the % load at which a profitability of 1.5 achieved decreases by about 10% to a load of 85% of ampacity for the 336 conductor.

In order to estimate the potential loss savings for all of Hydro One, data on the % loading of 1245 rural distribution feeders in 2003 was examined. The results are shown in Table 13. It indicates that conductor change out would be cost effective on 3% of the circuits. The data could not determine how much of each circuit could be reconductored. The loading data only applies to the section closest to the substation.

Table 13 Loading on Hydro One Distribution Circuits

% Ampacity	# circuits	% of circuits
80 – 90%	57	4.5%
90 – 100%	43	3.5%
> 100%	39	3.1%

The detailed cost and benefits from reconductoring can only be calculated for specific circuits. Increasing conductor size by two steps can require the use of larger poles and crossarms. Increasing conductor size outside of the normal conductor set would result in many increased costs for Hydro One, including purchase of equipment that can string the heavier conductors and increased inventory costs for more conductor and connectors. In individual cases there are often alternative methods for reducing the losses, such as rebuilding a parallel single phase line as a three phase line, or reconfiguring adjacent circuits to lower the load.

It is recommended that Hydro One conduct a detailed study of its circuits loaded greater than 95% to determine the most cost effective means of lowering the losses.

9 COST MODELS FOR LOSS REDUCTION

There are a number of options for the appropriate cost model with which to identify loss reduction projects that should be implemented in the present business environment. It is different for different stakeholders.

It might be considered that cost of losses are all incurred by customers as they put the load on the system and they determine the timing of the loads which result in peaks and highest losses. The customer however, does not control the voltage at which they are served or the distance of line to their facility. Distributors also have a substantial influence through their network configuration, thresholds for capacity reinforcement and the loss levels of the network equipment they install. Losses could therefore be considered to be controlled by both the customer and the distribution company.

Peak losses have a direct impact on the demand and therefore on the distribution plant required, and thus have direct costs to the distribution company in terms of requiring additional capital equipment and costs associated with the loss-of-life of station transformers. Losses incur costs on the utility such as:

- requirement to increase the size of assets on the network to transport units which will be lost further into the network.
- Cost to maintain the system for incremental kW
- cost of facility to handle higher loads
- cost to maintain assets with higher capacity
- cost of allocating losses to customers

Given the above, it can be argued that although there is no energy cost of losses to utilities, there is a cost of demand losses. System components have to be planned, designed operated and maintained to handle the losses of downstream components. The cost to transfer an extra unit of power is borne by the utility without direct compensation from the customer. This cost is a component of the capital operation and maintenance budgets and must be included in the rate base

For the utility, the cost of energy losses is a pass through cost, and therefore does not affect them financially. This consideration implies that there are no benefits that accrue to the utility if it decreases the system losses. However, the utility is allowed to earn a return on its capital investment in the system. If that capital investment is made to reduce losses, then there is a financial return to the utility for decreasing losses. This consideration implies that the benefits to the utility are substantial and independent of actual loss savings achieved. The security of the return on investment causes the latter consideration to out weigh the former, resulting in a net benefit to the utility for implementing loss reduction programs. The cost effectiveness of the reduction in losses is not an issue for this stakeholder.

For society as a whole, the reduction of losses increases the cost efficiency of the society, decreases resource depletion, decreases pollution and decreases the investment in generation facilities with its attendant financial risk. If the cost of losses is less than the cost of program implantation then the cost of electricity is reduced creating a better business climate and reducing the cost of living. However, there may be net societal benefits even if the cost of program implementation is above the cost of energy saved.

For the individual customers who purchase electricity the major effect is on the price of electric energy. If the cost of losses is less than the cost of program implantation then the cost of electricity is reduced. A cost model for this stakeholder would probably not include environmental costs.

For each stakeholder, the costs that should be included in the cost model are different. The table summarizes the various costs and which stakeholder requires them to be in the cost model.

The relative value of the various costs as recommended by the OEB Total Resource Cost Guide (Ref 6) using the avoided cost method are shown in the following table.

Table 14 Cost for Inclusion in Cost Model

Cost	$/kWh	Distribution Utility	Society	Customer
Energy Cost	0.066		✔	✔
Generation Capacity Cost	0.018		✔	✔
Transmission Capacity Cost	0.0014	✔	✔	✔
Transmission Loss Cost	0.002	✔	✔	✔
Distribution Capacity Cost	0.0018	✔	✔	✔
Distribution Loss Cost	0.006	✔	✔	✔
Environmental Costs	0.019		✔	

In Table 15 capacity costs were converted from $/kW to $/kW-h, for the purposes of comparison, by multiplying by the ratio of energy sold to peak power for the Hydro One distribution system (0.000245). When this is done it is clear that the energy cost is about 57% of the total avoided cost, or 69% if the environmental cost is not included.

In this report all of the costs have been included except the environmental cost. The environmental costs represent about 16% of the total.

10 REVISED TECHNICAL LOSS MANAGEMENT PROGRAMS

10.1 POWER FACTOR CORRECTION USING SHUNT CAPACITORS

The most recent loss analysis has indicated a potential for saving and forms the basis of the capacitor installation plan. The 2007 estimate indicates that shunt capacitor banks could be applied to 278 Hydro One feeders (12 with 450 kVAR units, 40 feeders with 300 KVAR banks and 226 feeders with 150 kVAR banks). When fully implemented these capacitors would result in annual energy savings of approximately 9.8 GW-hr, about a 0.5% reduction in distribution system energy losses. This translates to a 20-year Present Value of savings in the order of $8.7M. The capital and labor cost for these installations in a two year program, including the cost of analysis to determine optimal locations would be $4.1M for a profitability index of 2.1.

Additional loss reduction could be achieved with the installation of switched capacitor banks which would match the connected kVAR to the variations in the load. Since this loss reduction method would require control schemes to monitor voltage levels, time of day and / or status of switching equipment, the costs would increase substantially, and will require further investigation in future.

10.2 FEEDER PHASE BALANCING

The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. A considerable part of the Hydro One distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, a concerted effort to balance phases, can result in loss reduction. Phase imbalance is often expressed as the maximum phase current minus the average of the phase currents divided by the average of the phase currents. At the present time phase imbalances at the distribution stations on the worst third of the Hydro One feeders are in a range of 30% to 100 % indicating considerable room for improvement.

The recommended phase balancing program will target the 250 already identified circuits and the worst 192 of Hydro Ones’ distribution feeders yet to be identified over a 6-year period. It is estimated that at full implementation, balancing of these feeders will result in a 10.8 GW-hr annual energy saving. Since unbalance will recur with the passage of time, the benefits from this phase balance were estimated assuming a decline in energy savings over a 20 year period.

Considering only the first two years of this program, 250 circuits have already been identified and 64 more can be anticipated within two years, for a total of 314. This will result in an energy saving of 7.6 Gwh per year. The 20 year present value of avoided costs is about $5.2M. The cost to implement the phase balancing over a two year period would be $0.94M, for a profitability of 5.5.

10.3 CONDUCTOR CHANGE OUT

The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. Hydro One's long rural feeders are generally voltage-drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are the losses. Larger conductors require more capital expenditures and a balance must be found when sizing the conductors. The conductor size is typically optimized, through the planning process, when a feeder is initially installed. However, as the system evolves and conditions change from original plans, occurrences of sub-optimally sized conductors will materialize. Conductor change out on sections of a feeder that are heavily loaded can provide loss improvements. There are also other techniques for lowering the losses by lowering the load.

It is recommended that Hydro One conduct a detailed study of its circuits loaded greater than 95% to determine the most cost effective means of lowering the losses.

10.4 TRANSFORMER SIZING AND EFFICIENCY

The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. On the Hydro One system it is notable that on many feeders, the actual peak load on the feeder is only 20 to 40 % of connected kVA. This implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Consideration would have to be given to the cost of inventory for stocking smaller transformer sizes.

The 2007 loss analysis indicates that the optimal specification and sizing of distribution transformers could yield an estimated present value of savings over twenty years of $119 M.

Kinectrics has not been able to include all of the costs in the estimate since they are dependent on the internal business processes at Hydro One and on the market for distribution transformers. It is recommended that Hydro One conduct an internal study of the cost of changing to more efficient transformers and compare the costs with the benefits presented in this report.

10.5 SUMMARY OF BENEFITS

Lowering distribution system delivery losses will reduce overall system demand and provide additional network capacity for growth. Since system delivery losses are currently passed on to all customers, improvements in this area will benefit all customers.

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. The benefits of the capital expenditures over two years are present valued over twenty years.

Table 15 Economic Benefits

Program	**Maximum Reduction in Annual Energy Loss GW-hr**	**Avoided Energy and Demand Costs* $M**	**Cost of Program $M**	**Profitability Index**
PF Correction Capacitors - install cap banks on 278 feeders	9.8	8.7	5.1	1.7
Phase balancing - balance 314 circuits -2 years of a 6 year program	7.6	5.2	1.3	4.0

* Note: Present valued over a twenty year period

11 REFERENCES

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3. Kerry Diehl, “How HSVCs Improve Power Quality and Reduce Distribution Costs”, Electricity Construction and Maintenance January 2002

4. Ray Piercy, “Distribution System Configuration Study”, Kinectrics report 8307-010-RA-0001-R00, 2001

5. IPCEA Publication S-66-524, NEMA WC7-1971

6. Total Resource Cost Guide, Ontario Energy Board, September 8 2005

12 APPENDIX A 2005 Kinectrics Report K-011568-0010RA-0001-R00

1. CONCLUSIONS AND RECOMMENDATIONS

1.1 OVERALL LOSS ESTIMATE

A high level computation using the latest system component inventories and loading data has shown that the best estimate of the annual energy technical loss in Hydro One distribution systems is 5.05% of energy sales, with an expected range of 3.9 to 6.1%.

The loss breakdown by power system component is shown in the following table.

Component	**Estimated Loss as a Percent of Total Energy Sold**
Subtransmission Lines	2.33
Power Transformers No Load	0.21
Power Transformers Load	0.12
Distribution Lines	1.18
Distribution Transformers No Load	0.78
Distribution Transformers Load	0.19
Secondary Lines	0.24
Total	5.05

1.2 DISTRIBUTION LOSS FACTORS

The Distribution Loss Factors (DLFs) calculated based on these technical losses are shown in the following table and compared to the previous DLF values used by Hydro One.

Customer Type	**DLF in Present Rates**	**Total Estimated DLF**
Embedded LDC and Subtransmission Customers	3.4%	4.4%
Primary Customers	6.1%	6.8%

Secondary Customers	9.1%	9.6%

The DLFs in the above table include the technical and non-technical losses on the distribution system and an allowance of 0.6% for loss in the transmission system.

1.3 TECHNICAL LOSS REDUCTION PROGRAM

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and the avoided costs for generation, transmission, distribution and environmental impacts. The present value of the benefits has been calculated over twenty years. The overall benefit to cost ratio of the program is 5:1.

Program Savings

Program	**Maximum Reduction in Annual Energy Loss GW-hr**	**Avoided Energy Demand and Environmental Costs PV $M**
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

Program Costs

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

2. INTRODUCTION

As part of the support for the rate application to the OEB Hydro One has requested a study of the technical line losses on its electric power distribution system. The project included an overall assessment of technical energy losses, an allocation of loss to different types of customers resulting in distribution loss factors (DLF) for each type, and development of a program to reduce energy.

Energy losses on power systems can be divided into two broad categories, technical losses and non-technical losses. The majority of this report deals with technical losses, however a brief discussion of non-technical losses is provided in section 2.2.

2.1 DEFINITION OF TERMS

Distribution Loss Factor (DLF)
A factor used to increase the measured energy from a customer's meter to account for losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.08 but it is often expressed as a percentage using just the decimal part, for example 1.08 is expressed as 8%. It includes technical losses, an adjustment for theft and other non-technical losses and the supply facilities factor.

Supply Facilities Factor
A value added to the DLF to account for loss in the transmission system. This has been previously estimated to be 0.6% by Hydro One.

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current and transformer losses that include a conductor loss and a core loss. The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kW-h per year or as a % of the total energy sold in a year.

Non-technical Losses
Includes all unaccounted for energy other than technical losses. This can occur through theft, meter inaccuracies, billing errors etc.

Loss Allocation
When technical losses are not averaged over all customers on the system they are divided into parts and each part assigned (allocated) to a different customer or group of customers. The loss allocation can be either power or energy losses, but usually it is energy losses. It can be expressed in kW-h or as a % of energy sold to that customer or group of customers in a year. The loss allocation is often used as a basis for a DLF. The DLF for a specific customer group can be calculated by adjusting for the amount of energy sold to that group and adding a factor for non-technical losses and the supply facilities factor.

Loss Factor
A factor used to convert the power loss at peak load to the average power loss. It depends on the details of the load profile, i.e. how the load changes with time. It is often estimated based on an equation involving the load factor as follows:

$$\text{Loss Factor} = p \times \text{load factor} + (1-p) \times \text{load factor}^2$$

The constant "p" in this equation depends on the load profile. It is typically 0.3 for subtransmission systems, 0.2 for distribution lines, and 0.15 for distribution transformers and secondary circuits.

Load Factor
A factor used to convert peak power to average power. It is the ratio of the average power to the peak power.

2.2 NON-TECHNICAL LOSSESS

Non-technical losses occur as a result of the difference between the amount of electricity distributed to customers and the amount that is actually paid for. These losses occur because of the following:

- Theft, fraud, meter tampering/bypassing
- Faulty meters - resulting in the amount of electricity used being under-recorded.
- Incorrect records, billing errors

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales. (Ref 3).

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold (Ref 1) and the upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors (Ref 2).

Any distribution loss factor calculated from technical loss allocation must be increased to cover all forms of non-technical loss. In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) of the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales. This figure has been adopted in this report.

3. OVERALL TECHNICAL LOSS ESTIMATE

3.1 METHOD

There are two basic methods that can be used to calculate technical energy losses, a method based on subtraction of metered energy purchased and metered energy sold to customers and a method based on modeling losses in individual components of the system.

The method based on subtraction of energy sold from energy purchased is the traditional method outlined by the OEB. This method is not appropriate for Hydro One because of the extensive metering system that would be required and does not now exist. The existing meters do not total energy over the same time periods because they are manually read at fairly long intervals. More expensive metering would be required. Energy meters are also not installed at all intermediate levels of the system where they would be required to allocate losses to different types of customers.

The method of loss estimation based on modeling losses in individual components of the system has been used in this report in order to be able to allocate different amounts of loss to different types of customer within Hydro One. The following method was applied to each system component (subtransmission lines, power transformers, distribution lines, distribution transformers, secondary lines):

1. Identify different types of the component that would have different losses (e.g. different transformer ratings, line voltage levels, secondary line lengths etc.)
2. Assume a load profile for each component type (hours per year at each load level)
3. Calculate from the load profiles, values for load and loss factors for each component
4. Estimate the number of each type of component in the Hydro One system
5. Calculate the total loss at peak load and the annual energy loss.

The energy loss computation requires information on several basic factors: the inherent loss of the component, the profile of time varying load on the component, and the population of such components on the Hydro One system. The following sections describe the details of the loss computation for each separate type of component.

3.1.1 Subtransmission Lines

The number of subtransmission circuits at each voltage level and the total circuit length was available from spreadsheet “PSDB_Feeders_2005_07_14.xls” obtained in July 2005. There are 300 circuits at 44 kV, 221 circuits at 27.6 kV and 42 circuits at 13.8 kV. Circuits that are metered at the transformer station and/or owned by other utilities were not included. The 44 kV circuits were divided evenly into two different types, 44 kV in a developed rural area (surveyed lines and concession roads) and 44 kV in a sparse load rural area. The total length of subtransmission line was 15,800 km, obtained from Dx asset inventory numbers. A linear feeder topology was used for all types with four sub-stations per circuit in the developed rural areas and with two stations per circuit in all other types. An average value of conductor resistance was used based on the proportion of conductor sizes used in Hydro One. The circuit topology and the conductor sizes were based on an examination of Hydro One circuit maps.

The Hydro One load data spreadsheet (DNAMLoadingNov11.xls) provided the frequency distribution of total peak load on all sub-transmission circuits (78.7% of rating on average). The average peak loading was used in the calculation, adjusted to give the 2004 energy sold, obtained from "Dx Losses Customers Info.xls", but the resulting loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the load data spreadsheet. The factor was calculated as the weighted average of the ratio of the per unit loadings squared.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.2 Power Transformers

The most recent load data for Hydro One substations was available in a data base "TLL Database_Apr_18_release.mdb", obtained in April 2005, as the sum of the load on all circuits of a substation. The total number of substation transformers was obtained from a text file, "Dx transformers .doc" provided by Hydro One in July 2005.

Typical load and no-load loss data for power transformers was available from a detailed study of 170 power transformers in Hydro One Networks. The differences in percentage loss between different voltage levels and MVA size was negligible so all transformers were assumed to be the average size.

The number of customers with power transformers was obtained from the "TLL Database_Apr_18_release.mdb", obtained in April 2005. Some of these customers are metered on the high voltage side of their transformers and the transformer loss should therefore not be included in the Hydro One loss estimate. The exact number of these customers is not known but examination of many circuits diagrams discovered that most LDC customers are metered on the high side and most other customers are not. Therefore all non-LDC customer transformers were included and no LDC customer transformers.

The energy sold through substation and customer power transformers was available from a spreadsheet "Dx Losses Customers Info.xls" provided in July 2005. The data was from 2004. This is the most recent data available. The total number of transformers, the total energy sold and the resulting peak load on the transformers was compared with data from previous calculations to ensure that it was reasonable.

The average peak loading was used in the calculation of transformer losses but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the database. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The total loading was adjusted to give the correct annual energy sales through each type of power transformer.

Daily load profiles were obtained from data (based on load studies in the 1980s) for the different customer classes (residential, seasonal, farm, general <5 MW). This is the most recent load profile data available. The aggregate load profiles for the different types of customer are not expected to have changed significantly since this data was obtained. These daily load profiles were combined using the appropriate number of each type of customer for Hydro One into a total daily load profile. The Hydro One monthly load profile was combined with the total daily load profile to give a total number of hours at each load level in steps of 10% per unit. These hours were used to convert peak values into annual energy for both loss and energy delivered.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.3 Distribution Lines

Five different types of distribution line were modeled, based on voltage level (4.16, 8.3, 12.5, 25, and 27.6 kV). The number of each type was obtained from the spreadsheet "PSDB_Feeders_2005_07_14.xls" obtained in July 2005 and the frequency distribution of total load on each circuit was obtained from the data base "TLL Database_Apr_18_ release.mdb". A topology of a three phase main trunk with single phase laterals was used, with three main trunk sections and 25 lateral sections. The conductor sizes and lengths of each section were estimated based on examination of Hydro One maps. Loads were assumed to be evenly distributed. The total length of distribution line was 103,600 km, obtained from the Dx asset inventory numbers

The average peak loading for each circuit type was used in the calculation, adjusted to give the correct energy sold in 2004, but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The same factor was used for all types.

The loss was also adjusted by factors to account for the distribution of imbalance between phases on the circuits (obtained from the April database) and for the assumed power factor of 0.92. The power factor assumption was based on a small sample of circuits for which measured values were obtained for other detailed projects in recent years.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.4 Distribution Transformers

Sixty different types of transformer were modeled, including twelve different kVA sizes in five high voltage ratings. The no load and load losses for each type of transformer was obtained from a Kinectrics data compilation which is based on manufacturer's data.

The total number of distribution transformers was 470,543, available from the Dx asset inventory numbers. The number of transformers at each voltage level was calculated using the proportion of circuit km at each voltage level (from the April database) and the distribution of transformer sizes was obtained from previous studies of Hydro One circuits in the Kingston area.

The average peak load on each transformer was assumed to be the same for all types since there was no data to support differences. The average peak load was calculated to give the total energy sold to retail customers in 2004. The average peak loading for each type was used in the calculation but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor calculated for distribution lines was used for distribution transformers because the frequency distribution specific to transformers was not available.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.5 Secondary Lines

Five types of secondary line were modeled: residential year round (urban and rural), residential seasonal, farm and general. Three phase farm and large customer general classes were assumed to be metered close to the transformers without the use of Hydro One secondary circuits.

All were assumed to be 120/240 Volt secondary except general which was assumed to be 600/347 Volts.

Most secondary lines were assumed to be directly from the transformer with no secondary bus as described in the Hydro One Line design standard and were assumed to use 3/0 Al triplex conductor. Urban customers were assumed to have eight customers per transformer and a secondary bus parallel to the road and then a perpendicular service drop.

The lengths of line were assumed to be 15m, 50m, 75m, 25m, and 10m respectively for the different types of customer. The maximum in the line design standard is 75m. Farms are usually shorter than residences because a primary line is run back from the road. General customers have shorter secondary lines because the meter is usually installed close to the transformer before the secondary is split to provide multiple main load locations.

The proportion of customers in each type was obtained from the “Dx Losses Customers Info.xls” spreadsheet.

3.2 RESULTS

The overall technical loss results are shown below in Table 1. The overall loss estimate is 5.05% of energy sold. This is the sum of the annual losses (1,976 GWh) divided by the total energy sold by Hydro One in a year (39,165 GWh). This total energy does not include the energy sold by Hydro One to non-embedded LDCs and non-embedded direct customers. These customers are supplied through dedicated subtransmission lines that are metered at the transformer station. All the losses in those lines are accounted for by the customer since they occur downstream of the revenue meter.

The loss percentage may appear to be high compared to urban utilities and low compared to most rural utilities. Hydro One's loss percentage is dependent on the composite rural/urban nature of their system and the fact that Hydro One serves many customers directly from their subtransmission system. The losses in Hydro One are higher than those in urban utilities because of the large rural area served by Hydro One. Rural areas have longer power lines with fewer customers per kilometer of line which increases the line losses. Distribution transformer losses also tend to be higher in rural utilities because of the minimum practical size of distribution transformer and the lack of load diversity when it only supplies a single customer.

The losses in Hydro One appear lower than most rural utilities because Hydro One provides 48% of its energy sales to customers at the subtransmission level, without use of distribution lines, distribution transformers and secondary conductors. This is a much larger percentage than most rural utilities because Hydro One serves local distribution companies. This means that 48% of the energy does not flow through the components of the system that produce half of the losses.

Another consequence of the high proportion of energy sold at the subtransmission level is that a larger proportion of Hydro One's losses occur at this level (46%) than would be typical of most utilities. This makes the portion of loss attributed to other components look smaller. For example, the 5% of the loss occurring on secondary lines is more typically 10% for other utilities.

The energy delivered through the sub-transmission lines (35,000 GWh) is less than the total sold (39,165 GWh) because some of the energy is sold through high voltage substations supplied directly from the 115 kV transmission system.

Table 1 Summary of Loss Estimation Results

	Peak Power (delivered by component) (MW)	Annual Energy (delivered by component) (GW-h)	Power Loss at Peak (MW)	Power Loss at Peak (% of total)	Annual Energy Loss (GW-hr)	Annual Energy Loss (% of total)	Annual Energy Loss as % of total energy sold
Subtransmission Line	8,600	35,000	200	34	913	46	2.33
Power Transformer No Load	3,270	20,500	9	2	82	4	0.21
Power Transformer Load	3,270	20,500	11	2	48	2	0.12
Distribution Line	4,530	18,750	233	40	461	23	1.18
Distribution Transformer No Load	4,290	16,900	35	6	304	15	0.78
Distribution Transformer Load	4,290	16,900	37	6	74	4	0.19
Secondary Line	4,290	16,800	62	11	93	5	0.24
Totals			587	100	1,976	100	5.05

The total annual energy delivered by the subtransmission lines is less than the total purchased from the transmission grid (39,165 GWh) because some of the energy purchased flows through high voltage substations supplied directly from 115 kV. Similarly the total energy delivered by distribution lines is less than the energy delivered by distribution transformers and secondary lines plus the primary customers because some of those distribution transformers are directly connected to 27.6 kV subtransmission lines in south west Ontario.

4. CALCULATION OF DISTRIBUTION LOSS FACTORS

The total loss percentage is calculated with reference to the total energy sales. However, when a DLF is applied, it is only applied to the portion of the total sales actually delivered to a particular customer group. In order to fully recover the costs for losses allocated to the group the DLF must be larger than the loss expressed as a percentage of total energy sales.

To calculate the DLF for the subtransmission customers (embedded LDC's, embedded directs and Transmission class customers) the first step is to calculate the fraction of the total energy sold that is sold to this group (19,089 / 39,165) which is 0.48 of the total. This fraction of the loss on the subtransmission lines and power transformers must be allocated to these customers (0.48 x (913+82+48)) which is 500 GWh. The DLF from technical losses alone is then 2.6% (500 / 19,089). Adding 1.2% for non-technical losses such as theft gives a final DLF of 3.8%. This can be compared with the previous DLF for this group which was 2.8%. Most of the difference is that the previous 2.8% DLF only included 0.28% for non-technical losses. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 4.4%.

To calculate the DLF for primary voltage customers a similar procedure is used. They purchase 8.3% of the energy sold through subtransmission and 16.2% of the energy sold through distribution lines. Their allocation of loss is therefore 161 GWh (0.083 x (913+82+48) + 0.162 x 461). And the DLF due to technical losses is 5.0% (161 / 3249). Adding 1.2% for non-technical loss such as theft gives a DLF of 6.2%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 6.8%.

Secondary customers purchase 43% of the energy sold through subtransmission, 84% of the energy sold through distribution lines and 100% of the energy sold through distribution transformers and secondary lines. Their allocation of losses is therefore 1307 GWh (0.43 x (913+82+48) + 0.84x461 + 304 +74 + 93). The part of the DLF created by technical losses is 7.8% (1307 / 16,833). Adding 1.2% for non-technical losses such as theft gives a DLF of 9.0%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 9.6%.

The following table compares the previous DLF's used by Hydro One, with the new DLFs calculated in this study.

Table 2 Comparison of DLFs

Customer Type	DLF in Present Rates	Technical Losses part of DLF	Total Estimated DLF
Embedded LDC and Subtransmission Customers	3.4%	2.6%	4.4 %
Primary Customers	6.1%	5.0%	6.8%
Secondary Customers	9.1%	7.8%	9.6%

The DLFs in Table 2 include the 0.6% supply facilities loss factor.

5. SENSITIVITY STUDY

The assumed values for various parameters in the model that produced the global system loss estimate have been varied over their reasonable range to determine the probable error in the total estimate.

Table 3 Sensitivity Study Results

Parameter	**Value used**	**Maximum**	**Minimum**	**Range in Total Loss (as a % of estimated loss)**
Conductor size in main sections	556 AL and 336 AL	556 AL	336 AL	±12%
Factor adjusting for peak loading differences from average [note1]	1.8	+10%	-10%	±8%
Load level	normal	+10%	-10%	±6%
Load profile (load factor)	0.5	0.7	0.35	±4.5%
km of distribution line	103,000 km	+10%	-10%	±4%
Distribution line current imbalance	24% average	+10%	-10%	±4%
km of subtransmission line	15,800 km	+10%	-10%	±2.5%
Transformer no load loss	power 0.14% dist. 0.27%	+10%	-10%	±2%
Number of distribution transformers	470,000	+10%	-10%	±1.5%
Split of circuits between developed and rural 44 kV	50/50	70 / 30	50 / 50	±1.3%
Split of line lengths between developed and rural 44 kV	50/50	35 / 65	50 / 50	±1.2%
Transformer load loss	power 0.4% dist 1.4%	+10%	-10%	±1%
Number of power transformers	1425	+10%	-10%	±1%
Topology of subtransmission lines	both	Linear	branched	±0.7%
Length of secondary line	42,500 km	+10%	-10%	±0.7%
Resistance of secondary line	0.35ohms/km	+10%	-10%	±0.6%
Number of secondary circuits	925,000	+10%	-10%	±0.6%

Note 1 The factor adjusting for peak loading differences from the average converts the loss calculated from the average loading on the circuits or transformers into the actual loss created by the distribution of loading.

The cumulative effect of all the parameter sensitivities, some positive and some negative is expected to be ±22% of the estimated loss in GW-h or ±1.11% of the energy sold. This is a practical estimate of the probable range, not a “worst case”.

6. TECHNICAL LOSS MANAGEMENT PROGRAMS

Technical losses on distribution systems are primarily due to I^2R losses in conductors and magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated but may be minimized. In order to properly manage the inevitable losses it is necessary to understand the relative impact of different sources of losses. The largest source of losses is not always the easiest to reduce. Some sources can be reduced more cost effectively than others.

Canadian Electricity Association Technologies research has developed loss estimates for "typical" urban and rural distribution systems as shown in Table 4 below. Hydro One has primarily rural distribution with some pockets of urban development. Independent assessments of Hydro One's distribution system losses indicate that technical losses are in the order of 4.4% of the energy delivered to the distribution system. This represents annual energy losses of approximately 1,700 GW-hr. Losses occur on 3-wire subtransmission lines, 4-wire distribution lines, station transformers, line transformers and secondaries to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that vary with loading. The breakdown of these losses from the various causes is shown in Table 4.

Table 4 Typical Loss Values

	Estimated Loss as a Percent of Energy Sold		
Component	**CEATI Typical Urban**	**CEATI Typical Rural**	**Hydro One***
Subtransmission Lines	0.1	0.7	2.33
Power Transformers	0.1	0.7	0.33
Distribution Lines	0.9	2.5	1.18
Distribution Transformers No Load	1.2	1.7	0.78
Distribution Transformers Load	0.8	0.8	0.19
Secondary Lines	0.5	0.9	0.24
Total	**3.6**	**7.3**	**5.05**

* Note: This table does not include the non-technical losses or the supply facilities factor that is included in Hydro One's total Distribution Loss Factors.

Management of system losses is an on-going consideration in the planning, design, operation, purchase, upgrading and replacement of Networks' distribution facilities and equipment. Nonetheless, Networks believes that there is an opportunity to achieve incremental economic reductions in distribution system delivery losses through targeted investment programs. Modest reductions in losses can yield considerable benefit in terms of avoided cost of energy and demand.

Studies of Hydro One distribution losses have indicated that there are several methods that can be practically and economically applied to reduce distribution losses. These include:

1. Power factor correction using shunt capacitors
2. Balancing of load on phases
3. Reconductoring lines which presently have under-sized conductors
4. Installing properly sized high-efficiency transformers

Each method is limited in the amount of energy that can be saved as well as a penetration limit on the number of Hydro One sites that would be amenable to the particular loss reduction method. Furthermore each method has an associated cost of implementation. Table 5 shows the results of demand and energy savings that were achievable in applying loss reduction methods to particular Hydro One feeders. The Profitability Index is provided as an indicator of how the reduction in the cost of losses relates to the investment required to achieve these savings. The Profitability Index is calculated as the net present value of the savings in loss costs over twenty years divided by the cost of the loss reduction method.

Table 5 Effects of Loss Minimization Techniques Applied to Example Feeders

Loss Reduction Technique	Reduction of Peak Losses (% Peak Feeder Losses)	Reduction of Loss Costs (% Feeder Loss Costs)	Profitability Index
Capacitor application	3.1%	3.2%	4.2
Phase Balancing	2%	1.6%	5.4
Reconductoring	30%	29%	1.4
Re-sizing Distribution Transformers	2.3%	4.1%	0.1

6.1 DESCRIPTION OF THE PROGRAM

The Distribution Network Loss Reduction Program will involve identifying and implementing projects where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses.

The three major areas offering the best economic opportunities are described below and information on the project costs and financial benefits is provided:

- ***Power Factor Correction using Shunt Capacitors***

  Feeder power factors in the Hydro One distribution network are typically in the range of 0.85 to 0.95, depending on time of year, mix of customers, and customer usage patterns. Power factor correction can be achieved through application of shunt capacitor banks. Capacitors reduce feeder losses by providing reactive power compensation near the load, thereby reducing the current flow in the line. The challenge in capacitor application involves the determination of the location, size, number and type of capacitors to be placed in the system. Fixed and/or switched capacitors can be used in the system. Fixed shunt capacitors provide constant reactive power compensation and are suitable for loads having approximately constant reactive power requirements. Switched shunt capacitors are used in cases of load variability since they allow more flexibility in controlling the losses and voltage drop. Hydro One purchases rack mounted capacitors with pre-installed oil switches. Targeting feeders with the known poorest power factors will generate the highest contributions to loss reduction DSM.

A preliminary analysis has indicated a potential for saving and forms the basis of the capacitor installation plan. It indicates that shunt capacitor banks could be applied to 660 Hydro One feeders (70 feeders with 600 kVAR banks, 150 with 450kVAR units, and 440 feeders with 300KVAR banks). When fully implemented these capacitors would result in annual energy savings of approximately 53 GW-hr, about a 3.0% reduction in distribution system energy losses. This translates to a 20-year Present Value of savings in the order of $53M. The capital and labor cost for these installation in a two year program, plus analysis to determine optimal locations would be $10.3M. These costs and benefits are summarized in Tables 6 and 7 below.

Additional loss reduction could be achieved with the installation of switched capacitor banks which would match the connected kVAR to the variations in the load. Since this loss reduction method would require control schemes to monitor voltage levels, time of day and / or status of switching equipment, the costs would increase substantially, and will require further investigation in future.

- ***Feeder Phase Balancing/System Configuration***

The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. A considerable part of the Hydro One distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, a concerted effort to balance phases, can result in loss reduction. Phase imbalance is often expressed as the maximum phase current minus the average of the phase currents divided by the average of the phase currents. At the present time phase imbalances at the distribution stations on the worst third of the Hydro One feeders are in a range of 30% to 100 % indicating considerable room for improvement.

The phase balancing program will target the worst 750 of Hydro Ones’ distribution feeders in a 2-year period. It is estimated that at full implementation, balancing of these feeders will result in a 15GW-hr annual energy saving. Since unbalance will recur with the passage of time, the benefits from this phase balance were estimated assuming a decline in energy savings over a 20 year period. With this assumption, the 20 year present value of avoided costs is about $11M. The cost to implement the phase balancing over a two year period would be $2.2M.

- ***Re-conductoring***

The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. Hydro One’s long rural feeders are generally voltage-drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are the losses. Larger conductors require more capital expenditures and a balance must be found when sizing the conductors. The conductor size is typically optimized, through the planning process, when a feeder is initially installed. However, as the system evolves and conditions change from original plans occurrences of sub-optimally sized conductors will materialize. Reconductoring of sections of a feeder that are heavily loaded can provide loss improvements.

Though not often highly profitable, reconductoring can be very effective in reducing losses on circuits that are particularly overloaded. As a portion of the distribution loss reduction program a study will be conducted to identify the Hydro One feeders that are prime candidates for reconductoring with profitability greater than one.

- ***Transformer Sizing and Efficiency***

The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. On the Hydro One system it is notable that on many feeders, the actual peak load on the feeder is only 20 to 40 % of connected kVA. This implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Consideration would have to be given to the cost of inventory for stocking smaller transformer sizes.

The low profitability index in Table 5 indicates that the cost of replacing existing transformers is typically beyond the benefits achieved. This illustrates that distribution transformers must be sized appropriately on initial installation in order to achieve minimal transformer losses.

Therefore, a portion of the distribution losses program will include a review of transformer sizing practices including the cost-of-losses formula, loss-of-life, load growth and inventory considerations. The intent is to minimize future losses by ensuring correct sizing and the purchase of transformers with the highest efficiency that can be justified by a total life-time cost consideration.

Benefits

Lowering distribution system delivery losses will reduce overall system demand and provide additional network capacity for growth. Since system delivery losses are currently passed onto all customers, improvements in this area will benefit all customers.

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and are present valued over a twenty year period.

Table 6 Economic Benefits

Program	**Maximum Reduction in Annual Energy Loss GW-hr**	**Avoided Energy Demand and Environmental Costs PV $M***
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

* Note: Present valued over a twenty year period

Table 7 Program Budget

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

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APPENDIX A LOSS MANAGEMENT PROGRAM BACKGROUND, ASSUMPTIONS AND COMPUTATIONS

A1. Expected Technical Losses at Hydro One

Hydro One is a distribution utility with a mixed service area consisting of both rural and small urban areas. A recent study conducted by utilities in North East North America concluded that the technical losses of typical urban utilities range from 2% to 5% of energy sold and for typical rural utilities technical losses range from 4% to 10% of energy sold (Ref 4). It also concluded that the achievable level of energy efficiency is not the same for all utilities but varies depending on the details of the service territory and the past design practices. Present estimates of the technical losses at Hydro One have been in the range of 3.9% to 6.1% of energy sold (section 3). These estimates are for technical losses and do not include non-technical losses, such as theft.

A2. Available Loss Reduction Technologies and Approaches

The techniques that are most applicable to a specific utility system depend on which types of losses are the most significant on that specific system. There are no techniques that will be best in all circumstances. The amount of loss reduction that should optimally be implemented depends on the societal expectations, economic constraints, and competing values such as improved asset utilization. Improving asset utilization reduces overall capital costs but it increases the loading on equipment which also tends to increase losses.

There are two main sources of losses, conductors and transformers. Transformer losses can be reduced by design or loading changes. Design changes can be achieved by using lower loss steel in the transformer core, or by using windings with lower resistance, either by using copper instead of aluminum or by using larger wires or both. Since transformer losses depend on the design they can only be reduced by replacing a transformer with high losses with one with lower losses. Since transformers are expensive this is only feasible if done slowly as transformers are replaced for other reasons, such as age or under capacity.

The following methods can be used to lower conductor losses:

1. Using copper instead of aluminum
2. Using larger conductors
3. Using more transformer stations (shorter low voltage lines)
4. Using three phase lines instead of single phase
5. Installing capacitor banks
6. Balancing the load between conductors on the same line
7. Reducing peak loads by active or passive load control
8. Installing distributed generation

Some of these are methods that utilize capital costs and are basically unable to be retrofit on existing systems (3), some utilize capital costs but can be retrofit (1,2,4,5,7,8) and some utilize operations costs (6).

Choice of which method to implement first depends on both the technical efficiency (how much energy can be saved) and the economic efficiency (will savings be larger than costs). Previous studies have shown that the most cost effective methods are capacitor installation and phase balancing.

A3. Application of Loss Reduction to Hydro One

A3.1 Identification of Most Suitable Techniques

The most suitable techniques are efficient in both technical and economic terms.

The **installation of capacitors** reduces losses by correcting the power factor of the loads and thus reducing the current required to supply the same power and energy. The current flow in distribution feeders can be decomposed into active and reactive components. Applying a shunt capacitor, at the load end of the feeder, injects the capacitive current that results in reduction of the net reactive current. This result in a reduction of the overall line current and the effective apparent power at the load seen from the feeder. Therefore, as the current of the feeder is decreased, the conductor losses will be reduced. Moreover, the voltage at the load end is boosted which may allow better service to the customers. The amount of loss reduction achievable depends on the initial power factor. Ideally the best evaluation technique would be to measure the power factor on all circuits and calculate the current reduction that can be achieved on each circuit. However, at Hydro One the power factor is not measured on all circuits. A previous detailed study on eight Hydro One circuits found power factor varies from 1 to 0.92 with an average of 0.94.

Another suitable technique for loss reduction in Hydro One is **balancing the load** between conductors on the same circuit. Since many of the loads are on single phase lines it is never possible to get a complete balance. However, the latest data shows that the average imbalance on Hydro One distribution circuits is 26%. This means that the highest or lowest conductor current is 26% different than the average current. The balance of current between the phases is not a static quantity. It varies from one year to the next as loads grow, are added or removed from the system. Phase balancing is therefore a maintenance activity that needs to be done on a regular basis. The cost implementing this loss reduction technique is therefore a maintenance cost rather than a capital cost. An analysis of this loss reduction method is included in this report so that this method can be compared to the installation of capacitors and a suitable balance can be struck between implementing the two techniques.

A3.2 Estimation of Potential Energy and Peak Power Savings

The total potential for energy savings due to **capacitor banks** has been estimated from typical circuits. If an average power factor of 0.94 (ref cress) is assumed to be typical of the existing circuits then the most recent load data indicates that capacitor banks of at least 150 kVAr could be installed on 1560 of the 2700 circuits, assuming a minimum load of half the peak. With the assumed 0.94 power factor, this is estimated to reduce distribution line losses by 85 GW-h per year.

The kW savings in different loading periods has been estimated as follows based on modeling of typical circuits at each voltage level. The minimum single capacitor bank has been assumed to be 150 kVAr

	Winter			**Summer**			**Shoulder**	
	On peak	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
Hours	**602**	**688**	**1614**	**522**	**783**	**1623**	**1305**	**1623**
150kVAr	4.93	2.89	1.44	4.42	2.63	1.36	3.14	1.27
300kvAr	10.41	6.10	3.05	9.33	5.56	2.87	6.64	2.69
450kVAr	26.54	15.56	7.78	23.80	14.19	7.32	16.93	6.86
600kVAr	63.28	37.10	18.55	56.74	33.82	17.46	40.37	16.37

The potential energy and peak power savings from **phase balancing** has also been estimated based on analysis of typical circuits at each voltage level. It was assumed that after balancing the circuit would still be 10% unbalanced since this is an achievable minimum.

# Circuits Balanced	**Energy Savings per circuit MW-h**	**Peak Power Savings per circuit KW**
25	104	48
47	89	38
67	81	36
99	69	30
148	57	24
251	42	18
351	34	15
451	30	13
551	26	11
651	23	10
751	21	9

The decreasing energy savings per circuit is caused by the circuits with the largest imbalance being selected first. The first 25 circuits have 100% imbalance. By the last few rows of the table the 100 circuits between each row are moving from 30% unbalance to 10% unbalance.

Peak kW Saved in Different Time Periods

	Winter			Summer			Shoulder	
# Circuits Balanced	**On peak**	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
25	26.9	16.3	8.2	25.0	14.9	7.7	17.8	7.2
47	21.3	12.9	6.5	19.8	11.8	6.1	14.1	5.7
67	20.2	12.2	6.1	18.7	11.2	5.8	13.3	5.4
99	16.8	10.2	5.1	15.6	9.3	4.8	11.1	4.5
148	13.4	8.2	4.1	12.5	7.4	3.8	8.9	3.6
251	10.1	6.1	3.1	9.4	5.6	2.9	6.7	2.7
351	8.4	5.1	2.6	7.8	4.7	2.4	5.6	2.3
451	7.3	4.4	2.2	6.8	4.0	2.1	4.8	2.0
551	6.2	3.7	1.9	5.7	3.4	1.8	4.1	1.7
651	5.6	3.4	1.7	5.2	3.1	1.6	3.7	1.5
751	5.0	3.1	1.5	4.7	2.8	1.4	3.3	1.4

A3.3 Extent of Application of Loss Reduction Methods and Expected Achievable Savings

To estimate the savings that could be easily achieved by installation of **capacitor banks** it can be assumed that heavily loaded circuits will have a power factor of a maximum of 0.96. This is a conservative figure based on the known power factors. Assuming a minimum installation of 150 kVAr and a minimum load of half of the peak load, any circuit with a peak load of more than 1000 kW would have enough reactive power to install a capacitor bank. Circuits with more than 2200 kW load could have 300kVAR of capacitors installed, circuits with more than 3000 kW could have 450 kVAr of capacitors, and circuits with more than 4500 kW peak load could have 600kVAr of capacitors installed. The most recent circuit load data indicates there are 70 circuits that could have 600kVArs, 150 that could have 450 kVArs, 440 with 300kVArs and 900 that could have 150kVAr banks. This is a total of 1560 circuits with at least 150kVars. With the 0.96 pf assumption, the estimated energy savings in distribution line losses are 71 GW-h per year. Limiting the number of circuits to those which require the largest banks will increase the profitability index. If capacitors are applied to the 600 worst circuits, then 70 circuits with 600kVAr, 150 circuits with 450 kVAr, and 380 circuits with 300 kVAr could be installed. The estimated savings would be 50 GW-h per year. More capacitors could be installed if the power factor and minimum load of heavily loaded circuits was measured.

To estimate the savings that could actually be achieved by **load balancing** the diminishing returns evident in the table above have been taken into account. A reasonable level would be determined by the economic analysis. The savings from balancing last only a few years and gradually decrease in each year as the balance becomes poor again. A 20 year linear decrease is a reasonable assumption. In this case a 2 year program to balance the worst 750 circuits is proposed. This would save 15 GW-h per year at initial full implementation.

A3.4 Economic Analysis

The savings from the loss mitigation techniques were computed using the Avoided Cost methodology in the Navigant "Avoided Cost Analysis for the Evaluation of CDM Measures" report dated June 14, 2005.

Savings were computed both including and excluding environmental impacts using Table 23 and 21 of the Navigant Report respectively. Savings were further expressed as Present value over twenty years by applying a discount factor of 9.3% and an escalation factor of 2.5% to the tabulated values.

Distribution demand was evaluated at $6.5/kW however this value is expected to be high since it was computed by the Navigant localized method. Savings were computed neglecting the Distribution Demand factor and are provided in the Table below.

Savings for the mitigation techniques were computed over a 20 year period.

Capacitors were assumed to be installed 25% in 2006 and 75% in 2007. In the year of installation only half the energy savings of the banks installed in that year were received. In 2008 all the savings from all units was considered and these savings continued on to 2026.

Installed capacitor costs were considered to be as follows:

150kVAR	$14,500
300kVAR	$15,300
450kVAR	$16,000
600kVAR	$16,800
900kVAR	$19,500

250 circuits were considered to be **balanced** in 2006 and 500 additional in 2007. The per circuit cost of balancing was considered to be $3000 including one day's time for a bucket truck, crew and a technologist. Only half of the savings was considered in the year of installation. A factor was applied to reduce the energy savings in subsequent years to account for the gradual loss of the impact of balancing.

Avoided Energy and Demand Costs including Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	45.7	51.4	52.0	52.9
Phase balancing - balance 750 circuits	15	9.9	11.1	11.3	11.4

Note: Present value calculated over a twenty year period

Avoided Energy and Demand Costs without Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	40.2	45.8	46.5	47.3
Phase balancing - balance 750 circuits	15	8.6	9.9	10.0	10.2

Note: Present value calculated over a twenty year period

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