INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 1:

Reference(s): **A1/T2/S1**

Following publication of the Notice of Application, did the applicant receive any letters of comment? If so, please state whether a reply was sent from the applicant to the author of the letter. If yes, please file that reply with the Board. If no, please explain why a response was not sent and state if the applicant intends to respond.

RESPONSE:

THESL did not receive any letters of comment following publication of the Notice of Application.

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INTERROGATORY 2:

Reference(s): C1/T5/S1

This exhibit provides THESL's Conditions of Service Revision #9, Effective Date: February 22, 2010. With respect to this document:

a) Please identify any rates and charges that are included in the applicant's conditions of service and if there are any such rates and charges, provide an explanation for the nature of the costs being recovered.

b) If there are any such rates and charges, please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2009 and the revenue forecasted for the 2010 bridge and 2011 test years.

c) If there are any such rates and charges, please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

RESPONSE:

a) Please refer to the attached Appendix A.

b) Please refer to the attached Appendix B.

c) While all of THESL's distribution rates and charges as approved by the Board are set out on THESL's tariff sheet, THESL observes that the Board recognizes the ability of THESL and all other LDCs to obtain revenues from sources other than those distribution rates approved by the Board. Such revenues serve as revenue offsets in the calculation of an LDC's Base Revenue Requirement, which is reduced relative to what it would be in the absence of such revenue offsets.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

One such category of revenue offset arises where the Board permits LDCs, in certain circumstances, to apply rates and charges not individually approved by the Board. Specifically, the Electricity Distribution Rate Handbook permits LDCs to apply a charge or a rate to a customer without approval of the Board if the charge or rate is "either (i) a charge for a specific customer related to a cost recovery for the provision of one-time services, or (ii) a general customer charge that is a flow-through of third party costs".[1]

THESL rates and charges that do not meet the criteria specified in the Rate Handbook are reflected in its Conditions of Service and are charged directly to parties who cause those costs to be incurred. Those parties may or may not be customers of THESL. Such rates and charges have been established based on historical costs and may change from time to time in order to accurately recover THESL's costs to provide the service; consequently, the regulatory burden to both the Board and THESL is reduced by excluding these rates and charges from THESL's tariff sheet.

THESL does not object to the inclusion of such rates and charges on its tariff sheet provided that this practice is applied equally to all LDCs.

[1] First Generation Electricity Distribution Rate Handbook, Ch.9, page 1

Conditions of Service Rates & Charges

Item	Section	Ref: CoS Rev. #9 (page)	Description of Rates and Charges	Nature of the Costs Being Recovered
1	2.2.1 Disconnection & Reconnection- Process and Charges	34-35	"Customers working within the limits of approach to Toronto Hydro's overhead service conductors shall contact Toronto Hydro Line Protection for a quotation to have the service wires protected. If a disconnection and reconnection is required, Toronto Hydro will provide this service for a fee of $730.00 plus GST ($365.00 plus GST for the disconnection and $365.00 plus GST for reconnection)."	THESL charges these fees for disconnection and reconnection services required when a customer is working within the limits of approach to THESL's overhead service conductors.
2	3.8.2 Traffic & Railway Crossing Signals and Pedestrian X-Walk Signals/Beacons	85-86	"The Standard Allowance is the connections at Toronto Hydro's feed pole/lines and final connections at the top of the Customer's service mast (OH) or at Customer's protective device located in Customer's handwell, tap box, junction box, pedestal (UG) as determined by Toronto Hydro, and is recovered via a Basic Connection Fee of $365.00 plus GST (OH) and $580.00 plus GST (UG) per location/installation."	THESL charges these fees directly to the customer for unmetered connections to recover THESL's costs associated with making the connection.
3a	Section 5 -Tables, Table 2 - Service Connection and Disconnection Fee	102	Service Connection Fee: Standard Basic Connection recovered through hydro rates ($1,315.00)	THESL recovers the basic connection costs through its rates.
3b		102	Service Disconnection Fee: Class 3A - General Service 50 kW -999 kW (for Overhead-Single Service) $250.00	THESL charges this fee for a disconnection directly to the customer to recover THESL's costs associated with making the disconnection. These costs are not recovered through rates.
4	Section 5 - Tables, Table 3 - New or Upgraded Street Lighting Services - Point of Demarcation and Connection Charges	103	Basic connection fee of $365.00 and $580.00 depending on where the connection point is made.	THESL charges these fees for streetlighting connections directly to the customer to recover THESL's costs associated with making the connection.
5	Section 5 - Tables, Table 9 Toronto Hydro Distribution Connection Standards Price List	109	THESL makes available its Distribution Construction Standards to contractors and developers wanting to connect to THESL's distribution system. Sections of the Standards are available separately (ranging from $100 to $4,000) or as a complete set ($16,000) of all the sections. Updates of the Standards are offered for a maintenance fee ($1,000).	THESL provides a price list of its Distribution Construction Standards at the request of an external party and charges according to this price list for any standards that THESL provides.

Table 1: Revenues from Conditions of Service Rates and Charges ($000s)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Actual Year 2006	Actual Year 2007	Actual Year 2008	Actual Year 2009	Bridge Year 2010	Test Year 2011
1	**Revenue**						
2	Plant Relocates	1,206.5	1,233.2	964.1	677.7	0.0	696.3
3	Line Hose Removal/Install	1,201.0	1,519.4	1,368.1	1,130.5	0.0	326.9
4	Temporary Service Construction	1,428.7	2,118.9	1,810.1	1,108.4	1,837.5	1,053.6
5	Plant Removals/Demo	259.9	404.8	458.2	221.7	733.2	181.5
6	Misc Revenue	7,127.5	8,227.7	8,218.5	7,012.9	6,025.4	5,669.3
7							
8	Total	**11,223.6**	**13,504.0**	**12,819.0**	**10,151.2**	**8,596.1**	**7,927.6**

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 3:

Reference(s): **A1/T1/S1/p2**
D1/T8/S12/p1

In the first reference, THESL states that it "has filed with this application as Exhibit D1, Tab 8, Schedule 12, Appendix A, a plan that addresses the incorporation of distributed generation into its grid."

Appendix A of the second reference is a report dated July 12, 2010 by Navigant Consulting entitled "THESL Next Steps for DG Study." This is described as a "scope of work."

The Board's EB-2009-0139 Decision directed THESL to "continue its analysis of the incorporation of DG into its Central and Downtown areas. In that regard it shall file a plan concurrent with its filing according to its distribution system planning requirements." The Decision went on to state that the plan to be filed "will contain an adoption of and justification for the "next steps" listed in the Navigant study and referenced above, or in the alternative, rationale for an "alternative approach" to determining the optimal power system configuration for Central and Downtown Toronto."

a) Please state why THESL believes the "scope of work" study filed in this proceeding is in compliance with the Board's direction in the EB-2009-0139 Decision. Please include specific commentary of how the "scope of work" study meets the requirement for an adoption of and justification for the next steps outlined in the Navigant study filed in the EB-2009-0139 proceeding.

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b) Please provide an update on THESL's timeline and plans with respect to enabling distributed generation, particularly with respect to FIT and microFIT applications and in context of the recommendations of the Navigant "scope of work" referenced above.

RESPONSE:

a) THESL believes the "scope of work" study filed in this proceeding is in compliance with the Board's direction since the scope of work incorporates all three of the next steps identified in the Board Decision EB-2009-0139 which specifically include:

1) Costs and options for upgrading the short circuit capacity on THESL's distribution system. The deliverables include establishment of a "base case" and assessment of all 35 TS's serving THESL service area. As well the scope involves review of distribution system bottlenecks and associated costs to eliminate such limitations. Additionally the work addresses the CDM impacts, transmission system constraints and implications of upgrade plans.

2) Development of a Prudent approach to enabling DG. This involves developing criteria for the optimization of alternatives and derivation of the preferred solution. Consideration will be given to both social and economic benefits. Further, the evaluation of benefits will take place in recognition of related DG, system expansion and policy developments and associated timeframes.

3) Development of a high-level implementation plan. The THESL plan will include all of the entities involved in the implementation of an effective overall strategy to incorporate distributed generation.

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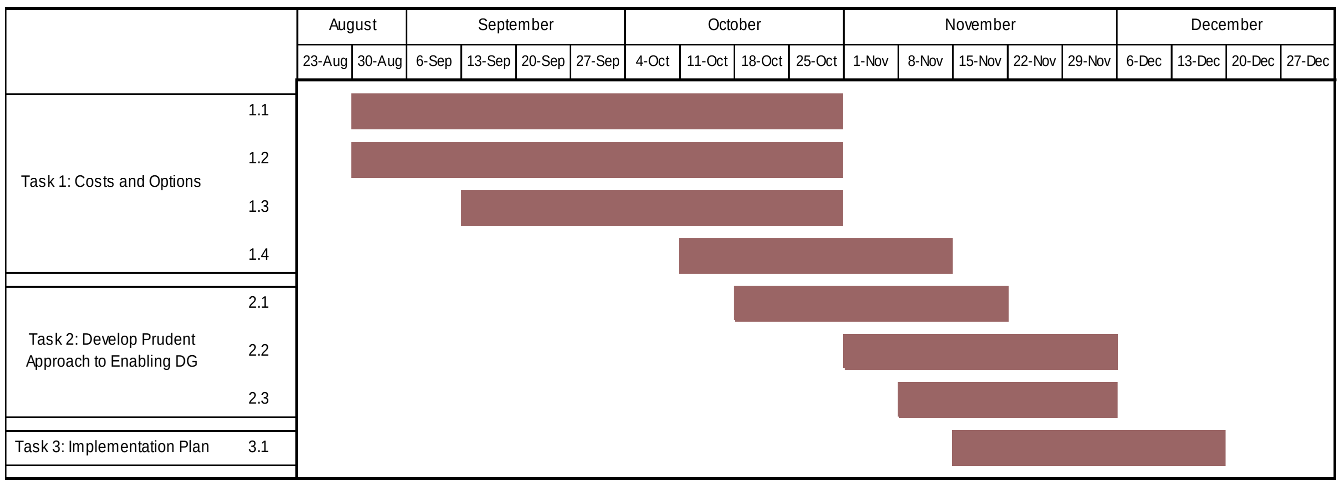
At the central core of the "scope of work" are the "next steps" outlined by Navigant Consulting and specified in the Board Decision EB-2009-0139 p31. These "next steps" have been adopted and incorporated into a contract with Navigant Consulting with specific deliverables.

Justification of this work is underscored by the high level of interest in the Feed-in-Tariff program and the requirement for THESL to develop a plan to accommodate DG as required under the *Green Energy and Economy Act*, *2009*. Furthermore, Central and Downtown Toronto faces a number of potential electricity system reliability challenges in the next five to seven years. Some of these challenges include additional area supply capacity, infrastructure renewal, and supply diversity to mitigate high impact - low probability events. To this end it is essential that THESL continue its analysis of incorporating DG into its distribution system.

b) THESL's plan in the context of the recommendations from the Navigant "scope of work" is to provide insight into THESL's distribution system costs and benefits for interconnecting significant levels of DG. THESL considers the analysis of the incorporation of DG to be an important element of its infrastructure spending and overall system plans. THESL has embarked on the work described in the DG Plan filed in EB-2010-0142 Exhibit D1, Tab 8, Schedule 12 and has executed a contract with Navigant Consulting which includes specific deliverables. The DG Plan is on track for completion and filing in 2011 as part of the 2012 EDR filing.

THESL's timeline for the Navigant "scope of work" is according to the schedule specified in the executed contract and shown in the figure below.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF



In terms of enabling DG connections with respect to FIT and for microFIT applications, THESL has successfully developed FIT standard guidelines for residential and commercial installations given various connection scenarios. As well, THESL has completed settlement on over 94 microFIT connections and completed over 29 connection impact assessments for FIT connection.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 4:

Reference(s): C1/ T4/ S1, App. B, p.5

When discussing its financial projections for its application, THESL provides a projected CPI rate for 2010 of 2.5%, which is stated as provided by the Conference Board of Canada.

a) Please confirm that this number came from page 4 of the Conference Board of Canada report "Economic Insights Into 27 Canadian Metropolitan Economies" from Spring 2010 included as Exhibit C1, Tab 4, Schedule 2, Appendix A. If not, please state how it was derived.

b) Please state whether or not this is the most recent version of this report and, if not, please provide the most recent version.

c) Please state whether this rate is used throughout the application when a CPI rate assumption is required. If not, please state what other CPI rate assumptions are contained in the application and when and why they are used.

RESPONSE:

a) The 2.5% Toronto CPI inflation rate is from the Conference Board of Canada's Winter 2010 Metropolitan Outlook report, issued in December 2009. This report was not filed.

b) The most recent Conference Board of Canada Metropolitan Outlook report (Autumn 2010) was issued in September 2010. It is attached as Appendix A to this Schedule.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

c) The CPI rate is communicated to operational units to apply as a factor for inflationary cost increases. The operational units consider other factors that impact their line item costs and include the test year cost requirements.

Toronto Hydro-Electric System Limited
EB-2010-0142
Exhibit R1, Tab 1, Schedule 4, Appendix A
Filed: 2010 Dec 6
(22 pages)

The Conference Board of Canada
Insights You Can Count On

Metropolitan Outlook 1 Autumn 2010

Economic Insights Into 27 Canadian Metropolitan Economies

ECONOMIC PERFORMANCE AND TRENDS

The Conference Board of Canada
Insights You Can Count On

Metropolitan Outlook 1: Economic Insights Into 27 Canadian Metropolitan Economies
by *Mario Lefebvre, Alan Arcand, Greg Sutherland, Robin Wiebe,* and *Jane McIntyre*

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This Issue

Book 1 covers Halifax, Québec City, Montréal, Ottawa–Gatineau, Toronto, Hamilton, Winnipeg, Regina, Saskatoon, Calgary, Edmonton, Vancouver, and Victoria.

Book 2 deals with St. John's, Saint John, Saguenay, Trois-Rivières, Sherbrooke, Kingston, Oshawa, St. Catharines–Niagara, Kitchener, London, Windsor, Greater Sudbury, Thunder Bay, and Abbotsford.

This publication is available through the Internet at www.conferenceboard.ca/edata.htm. For more information about the forecast, please contact our Information Specialists at 613-526-3090 ext. 444 or e-mail metro@conferenceboard.ca.

Contents

Highlights

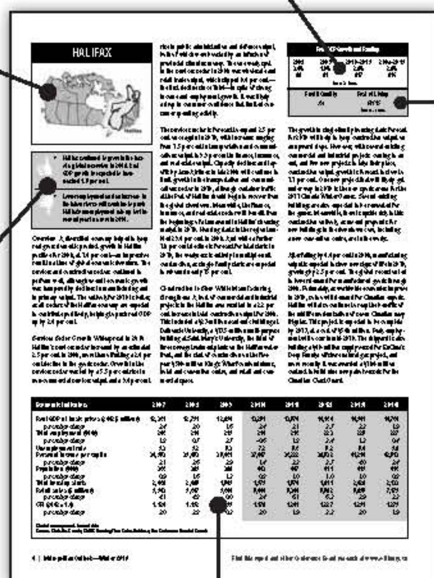
- **Toronto**'s economy will spring back by 4.7 per cent in 2010 as manufacturing and construction pick up.

Real GDP Growth and Ranking

The table displays four GDP growth rates: the last historical year, the current forecast year, the rest of the forecast period, and finally, a 10-year period comprising both historical and forecast data. Below each growth rate is a ranking that shows how the CMA fares against the other census metropolitan areas featured in the current edition of the *Metropolitan Outlook*.

Map

The census metropolitan areas (CMAs) are composed (defined by Statistics Canada) of the main city and the surrounding municipalities, towns, townships, villages, and parishes. The map shows the position of the CMA relative to other CMAs within the province.



Thumbs Up (Thumbs Down)

A thumbs up (down) indicates a favourable (unfavourable) element/event that has occurred within the census metropolitan area or that will certainly occur in the near future. It can also indicate a positive (negative) economic climate within the CMA.

Credit Quality

The credit rating is a current opinion (e.g., Dominion Bond Rating Service or Standard & Poor's) of the city's overall financial capacity (its creditworthiness) to pay its financial obligations. The rating applies to one of the individual cities within the CMA.

Debt Rating Service Scales

Dominion Bond Rating Service

Highest credit quality	AAA
Superior credit quality	AA
Satisfactory credit quality	A
Adequate credit quality	BBB
Speculative	BB
Highly speculative	B
Very highly speculative	CCC

Standard & Poor's

Highest quality	AAA™
Very good quality	AA
Good quality	A
Medium quality	BBB
Lower medium quality	BB
Poor quality	B
Speculative quality	C
Default	D
Rating suspended	Suspended

Cost of Living

Here the cost of living is shown as a ratio comparing the Consumer Price Index (CPI) level of the CMA and that of Canada.

Economic Indicators

Industrial Classification

Statistics Canada compiles data on gross domestic product and employment following the North American Industrial Classification System (NAICS). Within this system, two aggregate sectors exist—goods and services—each of which is subdivided into industrial sectors based on major type of production activity. The goods-producing sector includes the manufacturing, construction, and primary and utilities industries, whereas the services sector aggregates transportation and warehousing; information and cultural industries; wholesale and retail trade; finance, insurance, and real estate; business services; personal services; non-commercial services; and public administration.

Real GDP at Basic Prices

Gross domestic product at the CMA level is calculated using a weighted share of employment in both the CMA and the province and in provincial GDP. Hence, we are making the hypothesis that productivity is constant within an industry in different parts of a province. Total GDP is estimated by summing all the industrial GDP values. Values are posted in units of 2002 millions of dollars; hence, inflation effects are eliminated.

Total Employment

Total employment is the sum of employment in all industries. Data are presented in units of thousands, and an annual percentage growth value is also provided.

Unemployment Rate

The unemployment rate is the ratio of the number of unemployed workers to the total labour force.

Personal Income Per Capita

Personal income per capita is the sum of all revenues (wages, dividends, self-employment, etc.) received in a year, divided by total population. Data are in dollars and not corrected for inflation (current dollars).

Population

The population data include inhabitants of all municipalities that make up the CMA.

Total Housing Starts

Total housing starts represent the sum of multiple and single housing construction starts. Multiple housing includes any type of building that can lodge more than one household. Examples: apartment complex, condominium, duplex, and triplex.

Retail Sales

Retail sales are quoted in units of millions of dollars and are not adjusted for inflation (current dollars).

Consumer Price Index (CPI)

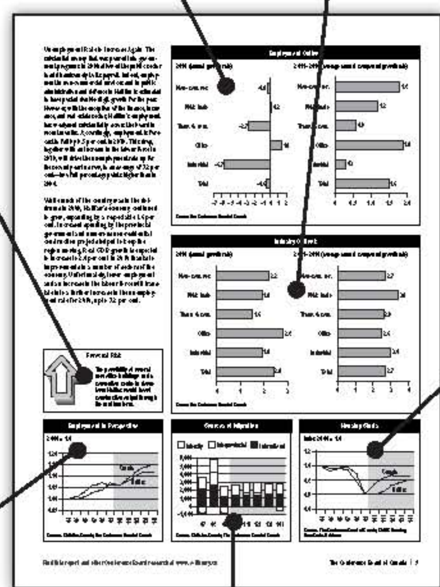
This index measures the cost of living for a typical urban family. It is composed of several goods priced after taxes. A benchmark year (1992, for example) is given the value 1.0. A value of 1.11 in 1999 is then interpreted as a growth of 11 per cent in the CPI between 1992 and 1999. Annual percentage growth rates are posted in italics below the CPI values.

Employment Outlook and Industry Outlook

Employment growth percentages for six specific sectors are shown for the current year and for an average yearly value over the next four years. The office sector is defined by these industries: information and cultural services; finance, insurance, and real estate; business services; and public administration. The industrial sector includes the manufacturing, construction, and primary and utilities industries.

Forecast Risk

To gauge the likelihood of the economic forecast unfolding, we indicate whether there is an upside or downside risk. As indicated by the arrow, the overall forecast is conditional on key assumptions that may boost or dampen the outlook.



Housing Starts

The graph demonstrates the growth in housing starts over a period of time. The base year (for example, 2002) is given the value 1.0. Hence, the following yearly data represent the growth value in comparison with 2002. For example, the value 1.2 means that housing starts have increased by 20 per cent since 2002. Two lines are shown in the graph, one for the metropolitan area and one for Canada.

Employment in Perspective

Using a base year (2002, for example) as a benchmark, this graph plots total employment growth against time. The shaded area of the graph represents the forecast horizon, and the forecast years are marked by the letter "f." The value 1.0 is given to the base year, and each subsequent year is used as a comparison; hence, the growth is clearly schemed. For analytical purposes, employment in perspective is shown with metropolitan and Canadian data. Canadian employment growth is represented by a line graph, while CMA employment growth is depicted by a bar graph.

Sources of Migration

Statistics Canada collects data for three types of population migration patterns: intercity, interprovincial, and international. Intercity migration is defined as the flow of population moving out of or into the metropolitan area to or from other cities in the province. Interprovincial migration represents population movements between the metropolitan area and other Canadian provinces, excluding the province in which the metropolitan area lies. International migration is the population movement between other countries and the metropolitan area. The graph plots the net values for the three demographic variables. The values can be read by matching the borderline of the bar to the left scale.

Real Estate

Depending on the availability of data, real estate information may include:

Downtown Office Market
The vacancy rate is the percentage of units available to lease in the CMA's downtown core. The average lease rate is quoted per square foot in a downtown Class A location.

Suburban Office Market
The vacancy rate is the percentage of units available to lease in the CMA's suburban areas. The average lease rate is quoted per square foot in a suburban Class A location.

Retail Market—Shopping Centre
The retail market consists of shopping centres, department stores, supermarkets, convenience stores, and power centres. The average lease rate is quoted per square foot in a prime street-front location.

Industrial Market
The industrial market consists of building units or assets devoted to production. The vacancy rate is the percentage of units available to lease, while the overall availability rate is the percentage of units available for sale. Average net rents or land values are quoted for the CMA's most active land markets.

New Housing Market
Absorptions refer to the number of newly completed housing units that are sold or rented. Growth in absorptions or prices refers to the percentage change from the previous year.

Resale Housing Market
Unit sales are the number of existing homes sold on the multiple listings service (MLS). Growth in sales or prices refers to the percentage change from the previous year.

Apartment Market
The apartment market consists of building units devoted to residential dwellings. Average rents are quoted for a two-bedroom apartment.

Comparative Employment

Employment is disaggregated into six sectors: industrial; office; transportation and warehousing; wholesale and retail trade; personal services; and non-commercial services. This table shows the share of each employment component relative to the total.

Dominant Industries

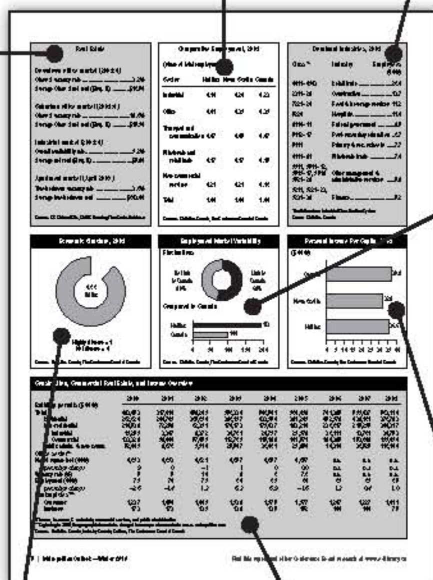
Using the North American Industrial Classification System (NAICS), this table presents the most important industries for the CMA, ranked by employment. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.

Employment Market Variability

Fluctuations
Fluctuation linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in employment in Canada between 1987 and the current year.

Fluctuation not linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in factors other than employment changes in Canada.

Compared to Canada
This bar chart represents the ratio of the standard deviation of total employment growth in the CMA to the standard deviation of total employment growth in Canada. The interpretation of this ratio is that the higher the number on the bar chart, the more volatile the labour market in the CMA relative to Canada.



Personal Income Per Capita

Personal income per capita is presented at the CMA, provincial and national levels. The information is presented in thousands of current (nominal) dollars.

Construction, Commercial Real Estate, and Income Overview

Building Permits
Historical data are in units of thousands for the number of building permits issued and are presented on a disaggregated level. Total building permits can be split into two main categories: residential and non-residential. Furthermore, the non-residential sector is divided into three sub-components: industrial; commercial and public administration; and non-commercial.

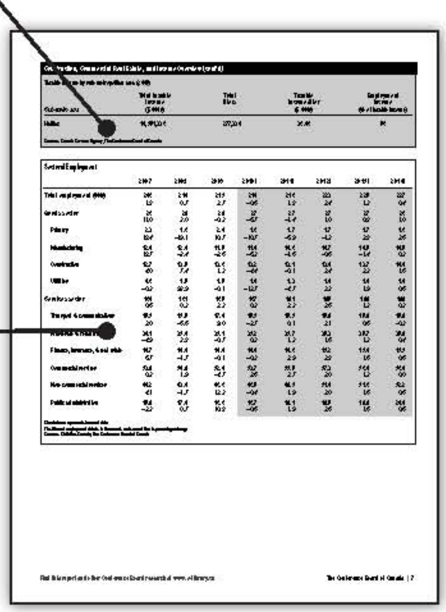
Office Sector
The total CMA office sector is quoted in units of thousands of square feet. This value evolves over time, and an annual growth percentage value is listed. The vacancy rate measures the amount of physically vacant space as a percentage of total inventory. Employment in thousands of units for the office sector is also quoted. The office sector is defined by these industries: information and cultural services; finance, insurance, and real estate; business services; and public administration.

Bankruptcies
Business and consumer bankruptcy figures are available from Industry Canada.

Economic Structure

Canada is set as the benchmark for economic diversity. It is proposed that the Canadian economy is well diversified; hence, a comparison can be made between the CMAs and the Canadian economy. The value 1 is given to a metropolitan area that has the same industrial structure as Canada. A value of 0 means that the CMA has a totally different economic structure and thus implicitly lacks diversity.

Taxable Income by Sub-Metropolitan Area
The latest data available from Revenue Canada have been used to compile the total taxable income for sub-metropolitan areas, in units of thousands of dollars, The average taxable income per filer is calculated according to the number of people who file a tax report. Furthermore, the portion of taxable income that comes from employment income is highlighted.



Sectoral Employment
The most important industries for employment are listed, based on NAICS data. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.

GLOSSARY OF ECONOMIC TERMS

Gross domestic product (GDP): A measure of the overall economic activity (value of goods and services produced) within an economy.

GDP at market prices: Represents the value of GDP as paid by final consumers; excludes subsidies but includes indirect taxes.

GDP at basic prices: Equivalent to GDP at market prices plus subsidies (product related) and minus indirect taxes (property and payroll but not sales taxes). It measures the value of producers' output. GDP at basic prices replaced GDP at factor cost, which was discontinued in January 2002.

Real* versus *nominal dollars: Real dollar economic measures such as GDP adjust for price changes and measure activity in a base year (e.g., 2002 $). Year-to-year changes in real or constant dollars reflect changes in quantities produced. Nominal dollar measures reflect quantities produced in prevailing prices (e.g., $ 000s). Year-to-year changes in nominal or current dollars reflect changes in both quantity and market prices.

Inflation: A sustained rise in the average level of all prices. The Consumer Price Index is one measure of inflation and is used as a proxy for inflation at the urban level.

Labour force: The total number of persons employed in both civilian and military jobs, plus the number of persons who are unemployed.

Participation rate: The total labour force expressed as a percentage of the population aged 15 years and over.

Canadian Census Metropolitan Areas

St. John's
Conception Bay South T
Portugal Cove-St. Philip's T
Pouch Cove T
Flatrock T
Torbay T
Logy Bay-Middle Cove-Outer Cove T
Bauline T
Paradise T
St. John's C
Mount Pearl C
Petty Harbour-Maddox Cove T
Bay Bulls T
Witless Bay T

Halifax
Cole Harbour 30 R
Shubenacadie 13 R
Halifax RGM
Sheet Harbour 36 R

Saint John
Saint Martins PAR
St. Martins VL
Simonds PAR
Saint John C
Musquash PAR
Lepreau PAR
Petersville PAR
Upham PAR
Hampton PAR
Hampton T
Rothesay PAR
Westfield PAR
Kingston PAR
Grand Bay–Westfield T
Greenwich PAR
Rothesay T
Quispamsis T

Saguenay
Saint-Fulgence M
La Baie V
Laterrière V
Chicoutimi V
Tremblay CT
Saint-Honoré M
Shipshaw M
Jonquière V
Lac-Kénogami M
Larouche M

Québec
Beaumont M
Saint-François P
Sainte-Famille P
Saint-Jean P
Saint-Laurent-de-l'Île-d'Orléans M
Saint-Pierre-de-l'Île-d'Orléans M
Sainte-Pétronille VL
Château-Richer V
L'Ange-Gardien P
Boischatel M
Sainte-Catherine-de-la-Jacques-Cartier V
Fossambault-sur-le-Lac V
Lac-Saint-Joseph V
Shannon M
Saint-Gabriel-de-Valcartier M
Lac-Delage V
Stoneham-et-Tewkesbury CU
Lac-Beauport M
Sainte-Brigitte-de-Laval M
Beauport V
Vanier V
Notre-Dame-des-Anges P
Sillery V
Québec V
Charlesbourg V
Saint-Émile V
Lac-Saint-Charles V
Loretteville V
Val-Bélair V
L'Ancienne-Lorette V
Sainte-Foy V
Cap-Rouge V
Saint-Augustin-de-Desmaures M
Wendake R
Pintendre M
Saint-Joseph-de-la-Pointe-de-Lévy P
Lévis V
Saint-Lambert-de-Lauzon P
Saint-Étienne-de-Lauzon M
Sainte-Hélène-de-Breakeyville P
Saint-Jean-Chrysostome V
Saint-Romuald V
Charny V
Saint-Rédempteur V
Saint-Nicolas V

Sherbrooke
Ascot Corner M
Stoke M
Saint-Denis-de-Brompton P
Waterville V
Lennoxville V
Ascot M
Fleurimont V
Bromptonville V
Sherbrooke V
Rock Forest V
Deauville M
Saint-Élie-d'Orford M
Compton M
North Hatley VL
Hatley CT

Trois-Rivières
Champlain M
Saint-Maurice P
Sainte-Marthe-du-Cap V
Cap-de-la-Madeleine V
Saint-Louis-de-France V
Trois-Rivières V
Trois-Rivières-Ouest V
Pointe-du-Lac M
Bécancour V
Wôlinak 11 R

Montréal
Lavaltrie VL
Saint-Antoine-de-Lavaltrie P
Richelieu V
Saint-Mathias-sur-Richelieu M
Chambly V
Carignan V
Saint-Bruno-de-Montarville V
Saint-Basile-le-Grand V
McMasterville M
Otterburn Park V
Mont-Saint-Hilaire V
Beloeil V
Saint-Mathieu-de-Beloeil M
Brossard V
Saint-Lambert V
Greenfield Park V
Saint-Hubert V
LeMoyne V
Longueuil V
Boucherville V
Sainte-Julie V
Saint-Amable M
Varennes V
Charlemagne V
Le Gardeur V
Repentigny V
Saint-Sulpice P
L'Assomption V
Lachenaie V
Terrebonne V
Mascouche V
La Plaine V
Laval V
Montréal-Est V
Anjou V
Saint-Léonard V
Montréal-Nord V
Montréal V
Westmount V
Verdun V
LaSalle V
Montréal-Ouest V
Côte-Saint-Luc C
Lachine V
Hampstead V
Outremont V
Mont-Royal V
Saint-Laurent V
Dorval C
L'Île-Dorval V
Pointe-Claire V
Kirkland V
Beaconsfield V
Baie-d'Urfé V
Sainte-Anne-de-Bellevue V
Senneville VL
Pierrefonds V
Sainte-Geneviève V
Dollard-des-Ormeaux V
Roxboro V
L'Île-Bizard V
Saint-Mathieu M
Saint-Philippe M
La Prairie V
Candiac V
Delson V
Sainte-Catherine V
Saint-Constant V
Saint-Isidore P
Mercier V
Châteauguay V
Léry V
Kahnawake 14 R
Maple Grove V

Beauharnois V
Melocheville VL
Les Cèdres M
Pointe-des-Cascades VL
L'Île-Perrot V
Notre-Dame-de-l'Île-Perrot M
Pincourt V
Terrasse-Vaudreuil M
Vaudreuil-Dorion V
Vaudreuil-sur-le-Lac VL
L'Île-Cadieux V
Hudson V
Saint-Lazare P
Saint-Eustache V
Deux-Montagnes V
Sainte-Marthe-sur-le-Lac V
Pointe-Calumet M
Saint-Joseph-du-Lac M
Oka M
Saint-Placide M
Kanesatake R
Boisbriand V
Sainte-Thérèse V
Blainville V
Rosemère V
Lorraine V
Bois-des-Filion V
Sainte-Anne-des-Plaines V
Mirabel V
Saint-Colomban P
Bellefeuille V
Saint-Jérôme V
Saint-Antoine V
Lafontaine V
Gore CT

Ottawa–Gatineau
Buckingham V
Masson-Angers V
Gatineau V
Hull V
Aylmer V
Val-des-Monts M
Cantley M
Chelsea M
Pontiac M
La Pêche M
Clarence-Rockland C
Russell TP
Ottawa C

Kingston
Frontenac Islands TP
Kingston C
South Frontenac TP
Loyalist TP

Oshawa
Whitby T
Oshawa C
Clarington T

Toronto
Pickering C
Ajax T
Uxbridge TP
Vaughan C
Markham T
Richmond Hill T
Whitchurch-Stouffville T
Aurora T
Newmarket T
King TP
East Gwillimbury T
Georgina T
Chippewas of Georgina Island First Nation R
Toronto C
Mississauga C
Brampton C
Caledon T
Mono T
Orangeville T
Oakville T
Milton T
Halton Hills T
New Tecumseth T
Bradford West Gwillimbury T

Hamilton
Burlington C
Hamilton C
Grimsby T

St. Catharines–Niagara
Fort Erie T
Port Colborne C
Wainfleet TP
Pelham T
Welland C
Thorold C
Niagara Falls C
Niagara-on-the-Lake T
St. Catharines C
Lincoln T

Kitchener
North Dumfries TP
Cambridge C
Kitchener C
Waterloo C
Woolwich TP

London
Central Elgin TP
St. Thomas C
Southwold TP
Strathroy-Caradoc TP
Thames Centre TP
Middlesex Centre TP
London C

Windsor
Amherstburg T
LaSalle T
Windsor C
Tecumseh T
Lakeshore T

Greater Sudbury
Whitefish Lake 6 R
Greater Sudbury C
Wahnapitei 11 R

Thunder Bay
Neebing TP
Fort William 52 R
Thunder Bay C
Oliver Paipoonge TP
Gillies TP
O'Connor TP
Conmee TP
Shuniah TP

Winnipeg
Taché RM
Ritchot RM
St. François Xavier RM
Winnipeg C
Headingley RM
Springfield RM
East St. Paul RM
West St. Paul RM
St. Clements RM
Brokenhead 4 R
Rosser RM

Regina
Pense No. 160 RM
Belle Plaine VL
Pense VL
Sherwood No. 159 RM
Regina C
Grand Coulee VL
Edenwold No. 158 RM
White City T
Pilot Butte T
Balgonie T
Edenwold VL
Lumsden No. 189 RM
Disley VL
Buena Vista VL
Lumsden T
Lumsden Beach RV
Regina Beach T

Saskatoon
Thode RV
Dundurn No. 314 RM
Dundurn T
Shields RV
Corman Park No. 344 RM
Saskatoon C
Langham T
Warman T
Blucher No. 343 RM
Martensville T
Bradwell VL
Allan T
Dalmeny T
Elstow VL
Osler T
Colonsay No. 342 RM
Clavet VL
Meacham VL
Colonsay T
White Cap 94 R
Vanscoy No. 345 RM
Delisle T
Vanscoy VL
Asquith T

Calgary
Rocky View No. 44 MD
Calgary C
Chestermere T

Canadian Census Metropolitan Areas

Cochrane T
Airdrie C
Irricana VL
Beiseker VL
Crossfield T
Tsuu T'ina Nation 145 R

Edmonton
Bruderheim T
Leduc County CM
Beaumont T
New Sarepta VL
Leduc C
Devon T
Calmar T
Sundance Beach SV
Thorsby VL
Itaska Beach SV
Golden Days SV
Warburg VL
Parkland County CM
Seba Beach SV
Betula Beach SV
Point Alison SV
Lakeview SV
Kapasiwin SV
Wabamun VL
Autumn Lake VL
Stony Plain T
Spruce Grove C
Strathcona County SM
Fort Saskatchewan C
Sturgeon County MD
Edmonton C
St. Albert C
Gibbons T
Redwater T
Bon Accord T
Morinville T
Legal T
Stony Plain 135 R
Alexander 134 R
Wabamun 133A R

Abbotsford
Abbotsford C
Mission DM
Fraser Valley H RDA
Upper Sumas 6 R
Matsqui Main 2 R

Vancouver
Langley DM
Langley C
Surrey C
White Rock C
Delta DM
Richmond C
Greater Vancouver A RDA
Vancouver C
Burnaby C
New Westminster C
Coquitlam C
Belcarra VL
Anmore VL
Port Coquitlam C
Port Moody C
North Vancouver DM
North Vancouver C
West Vancouver DM
Bowen Island IM
Lions Bay VL
Pitt Meadows DM
Maple Ridge DM
Semiahmoo R
Tsawwassen R
Musqueam 2 R
Coquitlam 2 R
Coquitlam 1 R
Burrard Inlet 3 R
Mission 1 R
Capilano 5 R
Barnston Island 3 R
Musqueam 4 R
Seymour Creek 2 R
Katzie 2 R
McMillan Island 6 R
Matsqui 4 R
Katzie 1 R
Langley 5 R
Whonnock 1 R

Victoria
North Saanich DM
Sidney T
Central Saanich DM
Saanich DM
Oak Bay DM
Victoria C
Esquimalt DM
Colwood C
Metchosin DM
Langford DM
View Royal T
Highlands DM
Sooke DM
Capital H RDA
Cole Bay 3 R
Union Bay 4 R
East Saanich 2 R
South Saanich 1 R
Becher Bay 1 R
Esquimalt R 10000
New Songhees 1A R
T'Sou-ke 1 R
T'Sou-ke 2 R

Abbreviations:
C = City
CM = County (Municipality)
CT = Canton (Municipalité de)
CU = Cantons unis (Municipalité de)
DM = District Municipality
IM = Island Municipality
M = Municipalité
MD = Municipal District
P = Paroisse (Municipalité de)
PAR = Parish
R = Indian Reserve
RDA = Regional District Electoral Area
RGM = Regional Municipality
RM = Rural Municipality
RV = Resort Village
SV = Summer Village
T = Town
TP = Township
V = Ville
VL = Village

Note: The 2001 census metropolitan areas reflect the agglomeration of several individual municipalities into one jurisdiction. For example, Halifax CMA now encompasses Halifax Regional Municipality, Cole Harbour, Shubenacadie, and Sheet Harbour. The Halifax Regional Municipality includes Bedford, Dartmouth, and Halifax, which were listed separately in the 1996 definition of the Halifax CMA.

In 2001, Statistics Canada increased the number of CMAs to 27. Abbotsford and Kingston were added.

Cross-City Comparison

Real GDP growth (per cent) 2009		Real GDP growth (per cent) 2010f		Real GDP growth (per cent) 2011f–2014f	
Halifax	0.9	Toronto	4.7	Calgary	4.2
Québec City	0.1	Hamilton	4.5	Edmonton	4.0
Winnipeg	–0.5	Saskatoon	4.5	Toronto	3.6
Ottawa–Gatineau	–0.7	Vancouver	4.3	Saskatoon	3.6
Montréal	–0.9	Edmonton	3.8	Vancouver	3.4
Victoria	–1.2	Ottawa–Gatineau	3.7	Regina	3.2
Vancouver	–1.7	Regina	3.5	Hamilton	3.1
Toronto	–2.3	Calgary	3.5	Halifax	2.7
Regina	–3.0	Québec City	3.4	Victoria	2.6
Saskatoon	–3.4	Victoria	3.3	Montréal	2.5
Hamilton	–3.8	Montréal	3.2	Winnipeg	2.5
Calgary	–4.5	Halifax	3.2	Ottawa–Gatineau	2.4
Edmonton	–5.1	Winnipeg	2.4	Québec City	2.4

CANADA

- Fiscal stimulus—especially infrastructure spending—will continue to contribute to economic growth this year.

- The European debt crisis and mixed signs among economic indicators in the United States suggest the path to a full global recovery will be bumpy.

Overview Canadian households, businesses, and governments have been enjoying the boost brought about by the strong economic recovery that typically follows a steep recession. Despite the woes still plaguing many of the world's developed economies, Canadian households have regained confidence and opened their wallets wide or taken advantage of record-low lending rates to boost spending. At the same time, government spending—specifically in the form of infrastructure spending—has been gaining more and more traction, helping to bolster construction and job growth. For businesses, the economic recovery has lifted sales and prices, helping to rebuild profits. The springboard start to the year suggests that after contracting by 2.5 per cent in 2009, real gross domestic product in Canada is forecast to advance by 3.6 per cent in 2010.

U.S. Recovery Still Hesitant The current forecast remains dependent on a modest (but crucial) recovery in U.S. household spending. While Americans have loosened their purse strings, the recovery is still fragile and will remain so until we see stronger employment and income gains. Shell-shocked U.S. businesses seem wary of hiring in such a tumultuous global environment. And while global financial and equity markets remain nervous about the European debt crisis, concern is growing that too quick a withdrawal of stimulus could restrain—or even derail—global economic growth. Despite these risks, our forecast assumes that the economic recovery in the United States will forge steadily ahead. Although the U.S. economy shed 350,000 jobs in June and July combined, the loss followed five consecutive months of gains. There's a long way to go before the 8 million jobs lost during the recession are recouped, but the situation has generally improved. Job creation, coupled with rock-bottom interest rates, should help stimulate home sales and prices—another key ingredient for a more solid and sustained recovery. These factors—stronger U.S. consumer spending and recovering new home construction—are key to providing a stronger lift to Canadian exports, particularly given the robust Canadian dollar.

Growth in Domestic Demand Set to Slow Somewhat Canadian households have clearly recovered from their recession blues—consumer spending growth turned positive in the second quarter of 2009 and has been accelerating ever since. This has provided a strong impetus to overall economic growth and is largely responsible for bringing our economy out of recession. The turnaround in spending is not surprising. All of the elements required were present: low financing rates, a turnaround in employment, a recovery in consumer confidence, and a reversal of wealth effects thanks to the turnaround in Canadian equity markets and a recovery in real estate values. More surprising is how strong the rebound in consumer spending has been. Perhaps buoyed by the prospects of future tax hikes and increased lending rates, growth in household spending has outpaced income and brought the aggregate household savings rate down from over 5 per cent in early 2009 to 2.8 per cent in the first quarter of 2010. Moreover, household debt as a share of income continues to swell—a factor that will hold back spending as increasing lending rates boost the cost of carrying debt. These conditions set the mood for much weaker growth in consumer spending over the second half of 2010 and into next year.

The rebound in consumer confidence and record-low mortgage rates led to frenzied activity in real estate markets beginning in the second half of 2009. But, as for consumer spending, the pace of residential construction will also ease sharply in coming months, as overall economic growth slows and higher interest rates kick in over the second half of this year. Moreover, the contribution from new fiscal stimulus will start to ease over the second half of 2010, before it drops in 2011. These domestic factors suggest that the pace of economic recovery will slow over the second half of this year and next year, with a slightly better performance expected for 2012.

With the federal and provincial governments pulling back hard on the reins of spending starting next year and a softening in the pace of global economic growth, the rise in Canada's overall GDP will soften from the expected 3.6 per cent this year to an anticipated 2.9 per cent in 2011.

Forecast Risk

- The risks to Canada's economic recovery come mostly from outside its borders, including concerns over the European debt crisis, lagging U.S. employment, and slower industrial production in China. Still, our sense is that the global and U.S. economies will adhere to a steady path of growth and recovery, and that the chances of a feared "double-dip" recession are remote.

Real GDP Growth

2009	2010	2011–2014	2005–2014
–2.5%	3.6%	2.9%	2.1%

Credit Quality

AAA

Standard & Poor's

Economic Indicators	2007	2008	2009	2010f	2011f	2012f	2013f	2014f
Real GDP at market prices (2002 $ millions)	1,311,260	1,318,055	1,285,604	1,332,284	1,370,312	1,414,020	1,457,313	1,494,891
percentage change	*2.2*	*0.5*	*–2.5*	*3.6*	*2.9*	*3.2*	*3.1*	*2.6*
Total employment (000s)	16,864	17,121	16,849	17,129	17,526	17,909	18,171	18,364
percentage change	*2.3*	*1.5*	*–1.6*	*1.7*	*2.3*	*2.2*	*1.5*	*1.1*
Unemployment rate	6.0	6.1	8.3	8.0	7.4	6.5	6.1	5.8
Personal income per capita	35,719	36,803	36,462	37,597	39,107	40,548	41,941	43,254
Population (000s)	32,887	33,276	33,690	34,065	34,433	34,809	35,195	35,586
percentage change	*1.1*	*1.2*	*1.2*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*
Single-family housing starts (000s)	118.9	93.2	75.7	101.5	99.3	102.8	101.6	102.1
Multi-family housing starts (000s)	109.4	117.9	73.4	87.0	90.4	96.0	98.5	99.9
Retail sales ($ millions)	412,565	427,896	415,413	444,401	465,148	486,193	506,579	525,697
percentage change	*5.9*	*3.7*	*–2.9*	*7.0*	*4.7*	*4.5*	*4.2*	*3.8*
CPI (2002 = 1.000)	1.114	1.141	1.144	1.169	1.200	1.227	1.253	1.280
percentage change	*2.1*	*2.4*	*0.3*	*2.2*	*2.7*	*2.3*	*2.1*	*2.1*

ONTARIO

- After being the province the hardest hit by the recession, Ontario is set to be the fastest-growing province this year, with an estimated GDP growth rate of 4.5 per cent.
- Employment growth is expected to push consumer demand up considerably this year.

Trade Recovery Is Well on Its Way Ontario's manufacturing sector is on the road to recovery. Indeed, the nominal value of vehicle shipments alone rose 77 per cent between July 2009 and July 2010. Overall, manufacturing output was up 9.3 per cent in the first quarter of 2010 from its recessionary low in the second quarter of 2009; it is forecast to be 10.3 per cent higher in 2010 as a whole and an additional 3.7 per cent higher in 2011. As a result, exports are expected to bounce back by 12.2 per cent this year. But most of the trade recovery already happened in the first half of 2010—it is expected to moderate over the next 18 months, with real exports forecast to advance by 5.7 per cent in 2011. Sturdy imports will again leave the trade sector a negative contributor to bottom-line growth over the next two years.

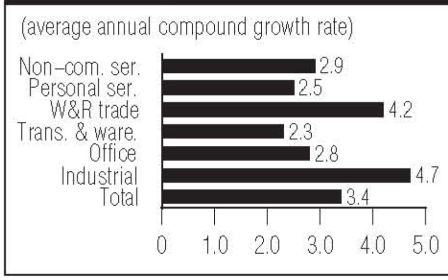
Investment Brisk Investment is playing a leading role in the recovery of Ontario's economy. Total investment in real terms is expected to grow at a brisk 11.8 per cent pace in 2010, thanks to strong residential and non-residential (business and government) investment. Overall investment growth is forecast to slow to 6.3 per cent in 2011, as government stimulus spending winds down and the Ontario government attempts to tackle the deficit. However, residential investment activity should remain steady.

HST Dampening Short-Term Consumption
The HST, which came into effect July 1, may put a slight damper on consumer expenditures this year as prices increase for certain goods and services, such as gasoline and professional fees. However, we expect that business costs savings will be passed on to consumers within the next few quarters. As well, to partially compensate for the added costs to consumers, the Ontario government has already sent out the first of three Ontario sales tax transition benefit cheques that will total $300 to $1,000 over the next year. Real consumer spending is forecast to advance by 3.1 per cent in 2010 and by 3 per cent in 2011.

Government Spending Set to Fall in 2011 The Ontario government is anticipating a deficit of $19.7 billion in 2010. The much stronger economic rebound so far this year will help public finances, but not enough to balance the books. With deeper pressures from health-care expenditures down the road, the government intends to control other expenses. It is trying to negotiate a wage freeze for the next two years for all public sector employees. If the affected parties and unions accept such a freeze, over 100,000 Ontarians will be affected, something that would likely dampen their consumption prospects. The Ontario government is already set to reduce its infrastructure spending next year, and real capital expenditures by all levels of government will contract by 4.2 per cent as the recession-fighting stimulus is clawed back.

Ontario's economy is already well on its way to recovery, after taking a 3.1 per cent hit to its GDP during the recession in 2009. Real GDP is projected to rise by 4.5 per cent in 2010, the highest of all provinces, and by 3 per cent in 2011.

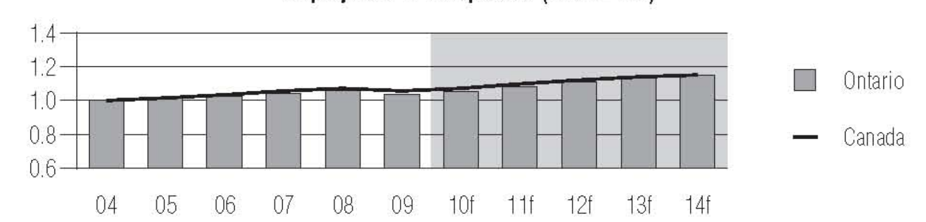
Industry Outlook, 2010–2014



Forecast Risk

- Although exports are expected to be up markedly, their growth depends on the European debt crisis not dampening American consumers' spirits.

Employment in Perspective (2004 = 1.0)



Real GDP Growth

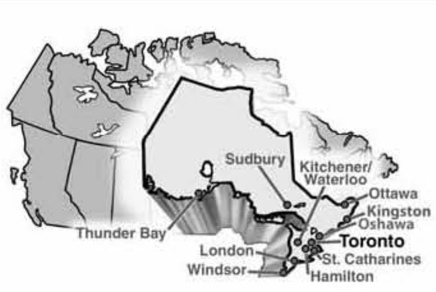
2009	2010	2011–2014	2005–2014
–3.1%	4.5%	3.1%	2.1%

Credit Quality

AA–
Standard & Poor's

Economic Indicators	2007	2008	2009	2010f	2011f	2012f	2013f	2014f
Real GDP at basic prices (2002 $ millions)	492,346	491,114	476,002	497,616	512,537	530,014	547,343	562,289
percentage change	*2.3*	*–0.3*	*–3.1*	*4.5*	*3.0*	*3.4*	*3.3*	*2.7*
Total employment (000s)	6,593	6,686	6,527	6,649	6,835	7,019	7,149	7,257
percentage change	*1.6*	*1.4*	*–2.4*	*1.9*	*2.8*	*2.7*	*1.8*	*1.5*
Unemployment rate	6.4	6.5	9.0	8.6	7.8	6.6	6.0	5.8
Personal income per capita	36,497	37,229	36,666	38,052	39,670	41,087	42,436	43,770
Population (000s)	12,777	12,917	13,052	13,188	13,351	13,520	13,699	13,886
percentage change	*1.0*	*1.1*	*1.0*	*1.0*	*1.2*	*1.3*	*1.3*	*1.4*
Single-family housing starts (000s)	37.9	31.1	22.6	32.8	35.4	40.3	40.8	41.2
Multi-family housing starts (000s)	30.2	44.0	27.7	30.8	36.3	42.8	45.3	46.1
Retail sales ($ millions)	145,965	151,672	147,920	159,044	167,997	175,730	183,095	190,406
percentage change	*3.8*	*3.9*	*–2.5*	*7.5*	*5.6*	*4.6*	*4.2*	*4.0*
CPI (2002 = 1.000)	1.108	1.133	1.137	1.171	1.203	1.229	1.256	1.283
percentage change	*1.8*	*2.3*	*0.4*	*3.0*	*2.8*	*2.1*	*2.2*	*2.2*

TORONTO



- Manufacturing output in Toronto is on track to post double-digit growth this year after declining in each year since 2005.
- Wholesale and retail trade has rebounded nicely in 2010, as consumers continue to regain confidence following last year's global recession.

Overview The recovery in Toronto's economy is now well under way, with real GDP growth expected to reach 4.7 per cent in 2010. Last year's recession hit the census metropolitan area's manufacturing and construction sectors hard, leading to a double-digit decline in goods sector output. However, increased demand, at home and abroad, has provided a lift to manufacturing output this year. At the same time, the construction sector has benefited from government stimulus spending and a rebound in housing starts, thanks to low interest rates, improved consumer confidence, and a strengthening job market. The recovery has also boosted the services sector, which is expected to expand by 3.9 per cent in 2010. Continued widespread growth should result in a further 3.6 per cent increase in real GDP next year.

Manufacturing Output Set to Rise Finally
Toronto's manufacturing sector posted the largest decline on record last year, contracting nearly 14 per cent, as the worldwide downturn pummelled demand. As a result, manufacturing employment slipped 12.7 per cent. Unfortunately, 2009 was not the first negative year for this industry—manufacturing output in the region had been falling steadily since 2006, and was weak for several years before that. The sector was hurt by a mild U.S. recession early last decade. It then fell victim to the high-flying loonie, which made Canadian goods more expensive in the U.S. market. It also had to contend with rising oil and gas prices, which particularly hurt the automotive industry, a big player in the region. Indeed, leading up to the recession, manufacturing output had already declined an average of 4.5 per cent per year from 2006 to 2008, while sectoral employment had dropped 5.3 per cent, on an average annual basis.

But a turnaround is now under way. By the third quarter of 2009, with economic conditions improving, manufacturing output began to rise, and it has continued to do so in each quarter since. Accordingly, the industry is expected to record a 9.7 per cent increase in output this year and a further 3.1 per cent gain for 2011. Output growth is then forecast to average 3.7 per cent per year from 2012 to 2014.

Housing to Lead Construction Rebound The construction sector in Toronto also suffered under the economic downturn. While work on several non-residential construction projects continued throughout the region last year, the residential market was weak, with housing starts tumbling 38.5 per cent. In level terms, starts slipped to 25,900 units in 2009, their lowest level since 1998. Both single and multiple-unit housing starts declined. Fortunately, new home demand picked up in last year's second half, spurred on by the beginnings of an economic recovery and very low interest rates. The turnaround has continued in 2010. As a result, housing starts are expected to increase by 18.6 per cent this year. And even though activity may slow down again in the coming months with interest rates forecast to rise, the stronger economy and healthy population growth should keep starts on an upward trend. Housing starts will increase by an anticipated average of 17 per cent per year from 2011 to 2012.

Real GDP Growth and Ranking

2009	2010	2011–2014	2005–2014
−2.3%	4.7%	3.6%	2.6%
#8	#1	#3	#5

Out of 13 CMAs

Credit Quality	Cost of Living
AA	*99%*
City of Toronto Standard & Poor's	Canada = 100%

Non-residential investment activity has also been healthy, thanks to projects funded by government stimulus spending, as well as several ongoing projects such as the Trump Tower and Maple Leaf Square. Other projects that are getting under way in 2010 include the second and third towers at the Bay Adelaide Centre, as well as upgrades and maintenance to Toronto's transit system. All in all, construction output is expected to advance by 5.4 per cent this year and by 5.3 per cent in 2011. There is potential for even greater non-residential construction growth, as Toronto will need to get ready to co-host the 2015 Pan Am Games with Hamilton. From 2012 to 2014, construction output is forecast to increase by 4.4 per cent per year.

Wholesale and Retail Trade Growth Strong A rebound in employment, combined with stronger income growth and improved consumer confidence,

Economic Indicators	2007	2008	2009	2010f	2011f	2012f	2013f	2014f
Real GDP at basic prices (2002 $ millions)	222,133	222,692	217,539	227,863	236,014	245,315	254,375	262,807
percentage change	*3.0*	*0.3*	*−2.3*	*4.7*	*3.6*	*3.9*	*3.7*	*3.3*
Total employment (000s)	2,865	2,920	2,890	2,949	3,044	3,140	3,229	3,300
percentage change	*2.3*	*1.9*	*−1.0*	*2.0*	*3.2*	*3.1*	*2.8*	*2.2*
Unemployment rate	6.8	6.8	9.5	9.0	8.2	7.1	6.3	6.0
Personal income per capita	38,453	39,187	38,549	39,738	41,331	42,768	44,269	45,665
percentage change	*3.2*	*1.9*	*−1.6*	*3.1*	*4.0*	*3.5*	*3.5*	*3.2*
Population (000s)	5,433	5,531	5,623	5,717	5,822	5,934	6,052	6,174
percentage change	*1.8*	*1.8*	*1.7*	*1.7*	*1.8*	*1.9*	*2.0*	*2.0*
Total housing starts	33,293	42,212	25,949	30,775	36,055	42,160	45,036	47,228
Retail sales ($ millions)	58,126	61,049	59,118	62,271	65,889	69,412	72,694	76,098
percentage change	*5.4*	*5.0*	*−3.2*	*5.3*	*5.8*	*5.3*	*4.7*	*4.7*
CPI (2002 = 1.0)	1.105	1.131	1.136	1.172	1.205	1.230	1.257	1.285
percentage change	*1.9*	*2.4*	*0.5*	*3.1*	*2.8*	*2.1*	*2.2*	*2.2*

Shaded area represents forecast data; f = forecast.
Sources: Statistics Canada; CMHC Housing Time Series Database; The Conference Board of Canada.

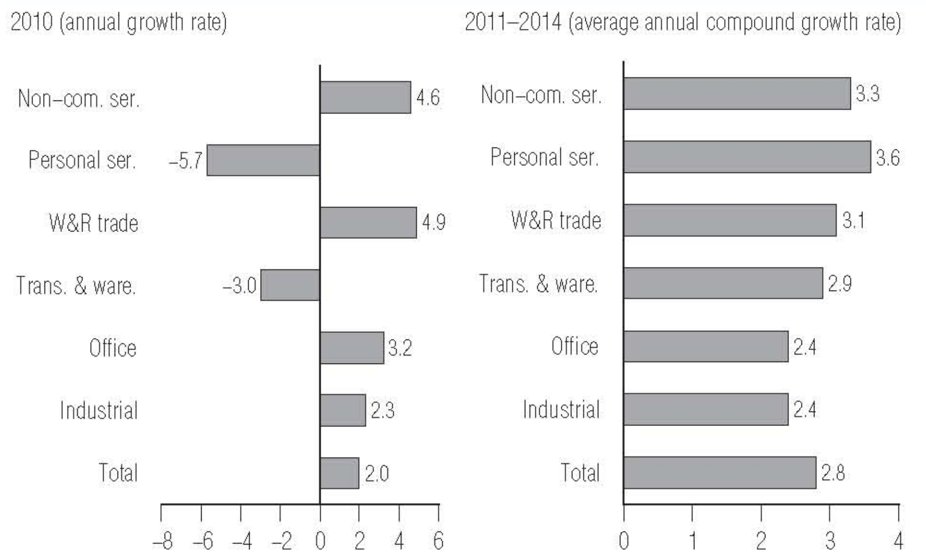
has resulted in healthy domestic demand this year. Indeed, retail sales are on track to increase by a solid 5.3 per cent in 2010. Accordingly, wholesale and retail trade output is expected to see the biggest gain in output on the services side of the economy, up by 8.4 per cent. As well, the strength in the housing market will lift finance, insurance, and real estate output by 4 per cent this year. Likewise, a rebound in the manufacturing sector will drive up transportation and warehousing output by 6 per cent. Public administration and defence output, meanwhile, is projected to post 5 per cent growth. In contrast, business services output is expected to contract by 0.6 per cent, down for the second year in a row. All in all, output growth in the services-producing industries is projected to come in at 3.9 per cent in 2010. Further gains in the economy next year should then help lead to widespread gains in all sectors. In total, services sector output will expand by an anticipated 3.6 per cent in 2011.

Toronto is expected to see a 4.7 per cent increase in real GDP this year and a 3.6 per cent gain next year as world economies continue to recover from last year's recession. The manufacturing sector is finally expanding in 2010—for the first time in five years. At the same time, stronger housing starts and government stimulus spending have provided a lift to the construction sector, while wholesale and retail trade output has benefited from improved consumer confidence, low interest rates, and a strengthening job market.

Forecast Risk

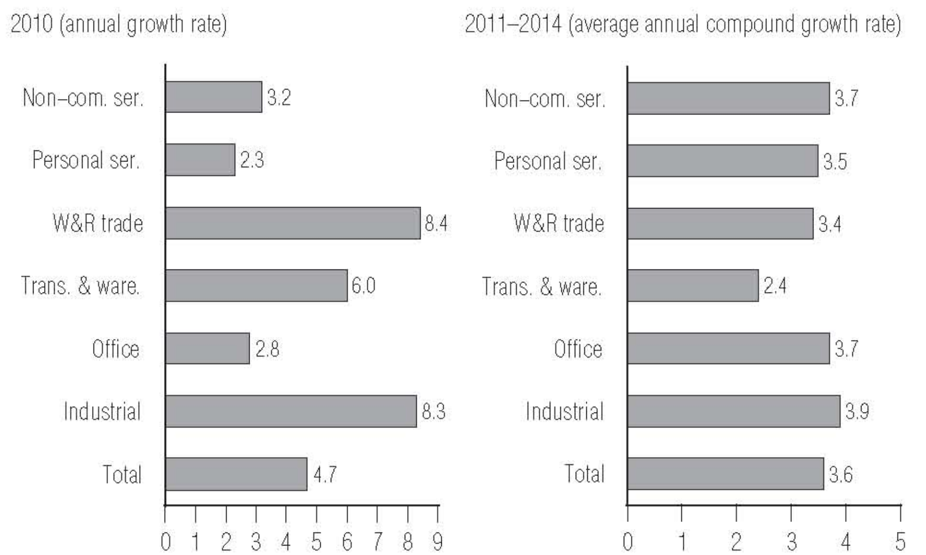
- Inventories of new homes could climb higher than expected, resulting in lower-than-anticipated housing starts next year.

Employment Outlook



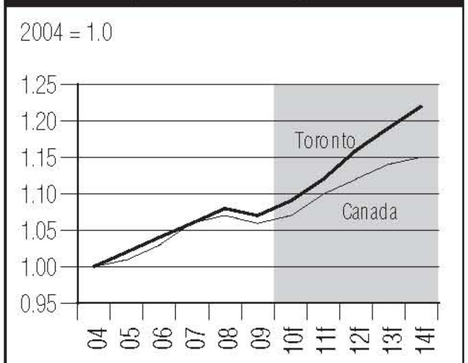
Source: The Conference Board of Canada.

Industry Outlook



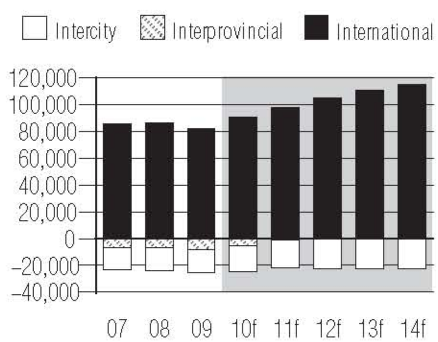
Source: The Conference Board of Canada.

Employment in Perspective



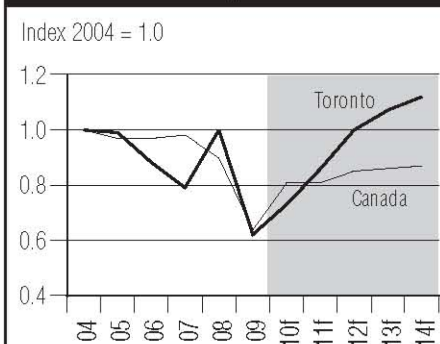
Sources: Statistics Canada; The Conference Board of Canada.

Sources of Migration



Sources: Statistics Canada; The Conference Board of Canada.

Housing Starts



Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

Real Estate

Downtown office market (2010Q2)

Class A vacancy rate 7.1%
Average Class A net rent ($/sq. ft.) $24.35

Suburban office market (2010Q2)

Class A vacancy rate 12.5%
Average Class A net rent ($/sq. ft.) $16.75

Industrial market (2010Q2)

Overall availability rate..................................7.5%
Average net rent ($/sq. ft.)............................$4.82

Apartment market (April 2010)

Two-bedroom vacancy rate 2.7%
Average two-bedroom rent $1,134.00

Sources: CB Richard Ellis; CMHC Housing Time Series Database.

Comparative Employment, 2009

(share of total employment)

Sector	Toronto	Ontario	Canada
Industrial	0.18	0.21	0.22
Office	0.33	0.28	0.25
Transport and warehousing	0.05	0.05	0.05
Wholesale and retail trade	0.15	0.15	0.16
Personal services	0.13	0.13	0.13
Non-commercial services	0.15	0.18	0.19
Total	1.00	1.00	1.00

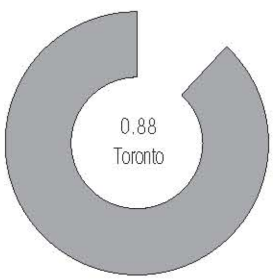
Sources: Statistics Canada; The Conference Board of Canada.

Dominant Industries, 2009

Class*	Industry	Employees (000s)
4411–4543	Retail trade	317.0
5211, 5221–23, 5231–39	Finance	170.9
2311–29	Construction	155.8
7221–24	Food & beverage services	138.2
4111–91	Wholesale trade	128.7
6111	Primary & sec. schools	113.2
5111–42	Info. & cultural ind.	108.0
5511, 5611–12, 5615–17, 5619 5621–29	Other management & administrative services	85.2
6211–19	Ambulatory health care serv.	80.8
5415	Computer sys. design serv.	77.8

*North American Industrial Classification System
Source: Statistics Canada.

Economic Structure, 2009

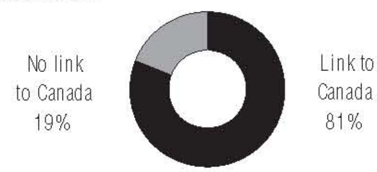


Highly diverse = 1
Not diverse = 0

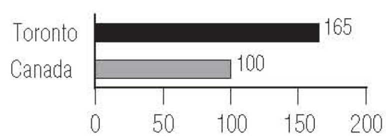
Sources: Statistics Canada; The Conference Board of Canada.

Employment Market Variability

Fluctuations

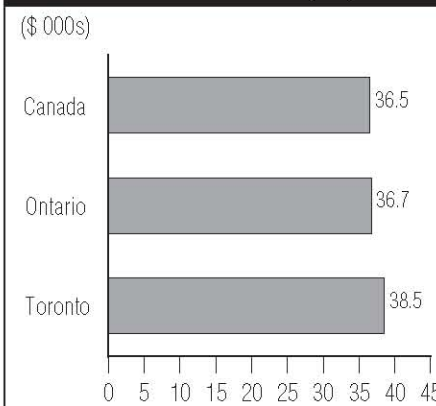


Compared to Canada



Sources: Statistics Canada; The Conference Board of Canada.

Personal Income Per Capita, 2009



Sources: Statistics Canada; The Conference Board of Canada.

Construction, Commercial Real Estate, and Income Overview

	2001	2002	2003	2004	2005	2006	2007	2008	2009
Building permits ($ 000s)									
Total	9,534,905	10,525,171	11,642,394	12,148,850	11,421,317	11,022,330	13,291,434	12,234,166	9,951,769
Residential	5,999,354	7,256,279	7,417,823	7,650,693	7,496,343	7,120,759	8,106,246	7,112,561	6,155,497
Non-residential	3,535,551	3,268,892	4,224,571	4,498,157	3,924,974	3,901,571	5,185,188	5,121,605	3,796,272
Industrial	663,585	561,471	963,349	911,916	679,156	725,652	915,017	728,565	488,656
Commercial	1,805,487	1,501,855	1,883,140	2,198,456	2,186,671	2,386,161	3,114,836	3,214,770	2,442,735
Public admin. & non-comm.	1,066,479	1,205,566	1,378,082	1,387,785	1,059,147	789,758	1,155,335	1,178,270	864,881
Office sector*									
No. of square feet (000s)	71,361	73,489	74,165	73,495	75,739	74,316	74,335	74,625	77,994
percentage change	*4.5*	*3.0*	*0.9*	*–0.9*	*3.1*	*–1.9*	*0.0*	*0.4*	*4.5*
Vacancy rate (%)	9.6	12.1	14.2	13.5	9.6	7.6	5.6	4.9	7.3
Employment (000s)	778	775	795	818	845	867	883	923	949
percentage change	*2.7*	*–0.4*	*2.6*	*2.9*	*3.3*	*2.6*	*1.9*	*4.6*	*2.7*
Bankruptcies**									
Consumer	8,477	9,210	10,321	10,691	10,983	10,349	10,597	12,208	15,423
Business	1,307	1,112	1,106	1,016	1,089	1,093	1,085	1,122	1,023

*Information & cultural industries; finance, insurance & real estate; business services; and public administration.
**Beginning in 2006, the geographic boundaries changed from major urban centre to census metropolitan area.
Sources: Statistics Canada; Industry Canada; CB Richard Ellis; The Conference Board of Canada.

Construction, Commercial Real Estate, and Income Overview (cont'd)

Taxable income by sub-metropolitan area (2007)

Sub-metro area	Total taxable income ($ 000s)	Total filers	Taxable income/filer ($ 000s)	Employment income (% of taxable income)
Toronto	88,716,561	1,925,120	46.08	63
Mississauga	20,960,980	516,080	40.62	73
Markham	12,363,243	278,730	44.36	69
Brampton	11,566,203	341,800	33.84	79
Oakville	8,857,800	126,970	69.76	69
Vaughan	6,459,174	141,780	45.56	75
Richmond Hill	6,331,242	138,660	45.66	72
Ajax	3,017,007	70,110	43.03	79
Pickering	2,971,685	63,830	46.56	75
Newmarket	2,812,325	58,200	48.32	74
Milton	2,500,066	49,180	50.84	77
Caledon	2,319,784	42,540	54.53	71
Aurora	2,195,045	35,120	62.50	73
Halton Hills	2,177,924	42,670	51.04	74
Orangeville	1,167,267	26,400	44.21	70
Georgina	1,120,428	29,890	37.49	74
Whitchurch-Stouffville	1,107,815	18,920	58.55	67
Rest of Toronto CMA	4,386,321	84,070	52.17	68

Sources: Canada Revenue Agency; The Conference Board of Canada.

Sectoral Employment

	2007	2008	2009	2010f	2011f	2012f	2013f	2014f
Total employment (000s)	2,865	2,920	2,890	2,949	3,044	3,140	3,229	3,300
	2.3	*1.9*	*–1.0*	*2.0*	*3.2*	*3.1*	*2.8*	*2.2*
Goods sector	601	606	525	537	552	561	577	591
	–2.2	*1.0*	*–13.4*	*2.3*	*2.8*	*1.6*	*2.9*	*2.5*
Manufacturing	404.5	391.7	342.2	341.9	346.7	345.4	349.0	353.1
	–4.4	*–3.2*	*–12.7*	*–0.1*	*1.4*	*–0.4*	*1.0*	*1.2*
Construction	168.7	183.3	155.7	166.9	176.4	185.4	196.6	205.8
	1.2	*8.7*	*–15.1*	*7.2*	*5.7*	*5.1*	*6.1*	*4.7*
Primary & utilities	27.5	31.3	27.0	28.0	28.9	29.9	31.2	32.1
	13.7	*14.2*	*–13.9*	*3.7*	*3.2*	*3.4*	*4.2*	*3.1*
Services sector	2,265	2,314	2,365	2,412	2,492	2,579	2,652	2,709
	3.5	*2.2*	*2.2*	*2.0*	*3.3*	*3.5*	*2.8*	*2.1*
Transportation & warehousing	136.7	163.6	155.0	150.3	160.8	164.9	166.8	168.7
	–1.9	*19.6*	*–5.3*	*–3.0*	*7.0*	*2.5*	*1.1*	*1.1*
Information & cultural industries	97.1	99.1	107.8	97.8	103.5	106.9	109.3	111.0
	–7.6	*2.0*	*8.8*	*–9.3*	*5.9*	*3.2*	*2.2*	*1.5*
Wholesale & retail trade	464.4	454.1	445.8	467.5	489.7	508.8	520.7	528.6
	1.1	*–2.2*	*–1.8*	*4.9*	*4.8*	*3.9*	*2.3*	*1.5*
Finance, insurance, & real estate	285.9	284.1	313.6	305.5	315.8	332.0	342.7	352.1
	–0.3	*–0.7*	*10.4*	*–2.6*	*3.4*	*5.2*	*3.2*	*2.7*
Business services	408.4	433.3	429.6	465.6	463.4	474.0	488.8	497.8
	5.4	*6.1*	*–0.8*	*8.4*	*–0.5*	*2.3*	*3.1*	*1.8*
Personal services	340.5	329.0	371.7	350.3	369.7	383.7	394.9	402.9
	8.6	*–3.4*	*13.0*	*–5.7*	*5.5*	*3.8*	*2.9*	*2.0*
Non-commercial services	440.0	443.9	444.3	464.9	481.1	498.3	514.8	529.9
	7.5	*0.9*	*0.1*	*4.6*	*3.5*	*3.6*	*3.3*	*2.9*
Public administration	91.8	107.1	97.6	110.2	108.2	110.4	114.0	117.7
	5.1	*16.7*	*–8.8*	*12.9*	*–1.8*	*2.0*	*3.3*	*3.2*

Shaded area represents forecast data; f = forecast.
First line of employment data is in thousands and second line is percentage change.
Sources: Statistics Canada; The Conference Board of Canada.

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INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 5:

Reference(s): B1/ T13/ S1

Table 1 shows Service Quality Measures for the period 2004 to 2009.

The measure "Emergency Response," which has a Board standard of 80%, shows a 2009 result of 79.5%, which is below the Board standard and also continues a decline from the 2007-2008 levels of 90% and 86% respectively.

Please provide an explanation for these results and state whether THESL is taking any measures to deal with them and if so what such measures would be. If not, please state why THESL believes that no measures are necessary.

RESPONSE:

THESL's emergency response of 79.5% in 2009 was negatively impacted by 21, non-MED (Major Event Day) storm days. These storm events generated large volumes of emergency/outage calls within a few hours. In these instances, THESL's crews were not always able to meet the one-hour response times, and emergency response performance declined.

In 2010, THESL has implemented GPS vehicle location technology in all its vehicles to more efficiently dispatch calls to the nearest available crew. Additionally, THESL has increased the number of crews that may be immediately released from planned work activities in order to provide escalated emergency response when needed. THESL's 2010 emergency response measure is at 82% as of October 31, 2010.

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INTERROGATORY 6:

Reference(s): **B1/ T14/ S1**

This exhibit discusses THESL's Electricity Infrastructure Reliability Performance Indicators, specifically SAIFI, SAIDI and CAIDI.

a) Please state whether or not THESL breaks down these indicators into more disaggregated levels of its service area (e.g. Old City of Toronto, Scarborough, etc). If THESL does undertake such breakdowns, please state the extent of the disaggregation undertaken and provide the disaggregated results. If not, please state why not.

b) Please discuss how THESL links its capital expenditure program to the needs of specific areas of its service territory. Please also discuss how THESL ensures that its capital expenditures are targeted to deal with reliability issues.

RESPONSE:

a) THESL disaggregates its Reliability Performance Indicators to the feeder level only.

b) The needs of specific areas are determined by the needs of the assets within those service territories. THESL ensures that its capital expenditures are targeted to deal with reliability issues through the application of its asset management approach. The methodologies and tools that comprise this approach (Reliability Centred Maintenance, Asset Condition Assessment, Feeder Investment Model and Asset Investment Strategy) are heavily focused on identifying and evaluating system or asset reliability concerns on which capital projects can be targeted. More details about the THESL asset management approach can be seen in Exhibit C1, Tab 6, Schedule 1.

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INTERROGATORY 7:

Reference(s): B1/ T14/ S1

Table 4 “Reliability Performance Without MEDs and Loss of Supply” shows that while SAIFI decreased from 1.66 in 2008 to 1.51 in 2009, both SAIDI and CAIDI increased in 2009 relative to 2008 levels.

On page 6, it is stated that “Generally, system reliability performance has shown improvement between 2008 and 2009, some of which may be attributable to THESL’s investment program.”

Please state why THESL considers that generally system reliability performance has shown improvement between 2008 and 2009 when two of the three indicators have deteriorated.

RESPONSE:

SAIFI improved for defective equipment, adverse environment and human element. This indicates fewer customers interrupted due to each cause as a result of increased robustness of the distribution system. SAIDI improved for tree contacts, adverse environment and human element. SAIDI deteriorated slightly for defective equipment and significantly for loss of supply. CAIDI is a function of SAIDI and SAIFI, specifically SAIDI divided by SAIFI. Since SAIFI is the denominator in the equation, as it improves (gets smaller) then CAIDI will appear to deteriorate unless SAIDI improves drastically as well. Overall, the phrase “generally system reliability performance has shown improvement” is referring to the SAIDI and SAIFI impact of forced outages

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

excluding loss of supply where SAIFI has clearly improved and SAIDI has mostly remained stable.

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INTERROGATORY 8:

Reference(s): **B1/ T14/ S1**

Please provide THESL's achieved reliability performance for the period 2006 to 2009 for SAIDI, SAIFI and CAIDI, with and without Loss of Supply interruptions but including Major Event Days (MEDs), by filling out the following table.

	All Service Interruptions			Service Interruptions excluding Loss of Supply (Cause Code 2)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2006						
2007						
2008						
2009						

RESPONSE:

	All Service Interruptions			Service Interruptions excluding Loss of Supply (Cause Code 2)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2006	1.57	2.17	0.72	1.38	1.90	0.72
2007	1.95	2.28	0.85	1.85	2.04	0.91
2008	1.24	1.76	0.70	1.22	1.66	0.73
2009	2.91	1.87	1.55	2.77*	1.71	1.62

*0.91 SAIDI contribution from Dufferin TS flood. This incident was accounted to the Adverse Weather cause code and not Loss of Supply.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 9:

Reference(s): **Issues List Decision and Procedural Order No. 2, p.4**

The above reference stated that:

"The Board finds that Issue 1.5 is relevant to the present proceeding and will be on the Approved Final Issues List. The Board finds that it is appropriate to incorporate this issue to allow parties to explore the full range of approaches available to deal with the longer term issues raised by Toronto Hydro's application."

a) Please provide THESL's views, with explanation, as to whether or not the rates arising out of the Board's Decision on this application would serve as an appropriate and robust starting point for applying the 3rd generation incentive regulation formula annually for the next three years.

b) If THESL does not consider that the rates arising out of the Board's Decision on this application would serve as an appropriate and robust starting point for applying the 3rd generation incentive regulation formula:

   i. please explain what conditions or factors need to be considered to establish appropriate rebased rates going into an incentive regulation formula-based approach

   ii. please provide THESL's views on whether or not its 2012 rate application should be based on 2012 rates calculated based on a cost-of-service approach, along with a proposal for an incentive mechanism for adjusting rates in 2013 and subsequent years

c) Please identify the process that THESL believes the Board should follow to examine alternative methodologies for setting THESL's rates following the completion of the present proceeding. Please provide details of each major step, including timing, for the process identified.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

RESPONSE:

a) THESL does not believe that the rates arising out of the Board's Decision in this case could serve as an appropriate and robust starting point for applying 3rd Generation IRM, due to the characteristics of 3rd Generation IRM (3GIRM).

Specifically, THESL believes that 3GIRM is inherently inappropriate for THESL's circumstances since it does not recognize or accommodate increases in revenue requirement apart from those stemming from the net of the inflation factor less the stretch-adjusted productivity factor. In particular, 3GIRM does not accommodate the increases in revenue requirement that must attend significant growth in ratebase, and associated growth in operating costs, directed to infrastructure renewal, workforce renewal, and utility modernization.

In this application and in several previous to this, THESL has presented extensive and thorough evidence on the need for significant re-investment in its infrastructure. This reinvestment is occurring on an ongoing basis and at levels that substantially exceed depreciation. THESL's evidence also demonstrated the need for workforce renewal in the face of cresting retirements and materially expanded workplans, and for utility modernization.

These are real cost pressures that cannot be addressed within the framework of 3GIRM. In previous applications, the Board has approved capital expenditures significantly in excess of depreciation. Consistent with both its previous proposals and its long term capital plan, THESL is again proposing capital expenditures substantially greater than depreciation. As the Board is aware, any approved capital expenditures in excess of depreciation entail an increase in ratebase. Any increase in

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

approved ratebase necessitates an increase in revenue requirement. By design, 3GIRM does not allow for such increases.

Revenue requirement in a given year supports the ratebase found in that year, not the larger ratebase that exists in a subsequent year when capital additions exceed depreciation. Furthermore, the Board has expressly denied the use of the 3GIRM capital adjustment mechanism to accommodate secular, predictable growth in ratebase, for example in the EB-2008-0187 Decision on a Hydro One application.

Similarly, if operating costs grow in real terms due to the factors noted above they cannot be supported by an essentially static revenue requirement, even assuming no growth in ratebase.

In summary, no set of rates found for a particular year would be appropriate as a starting point for 3GIRM to be applied to THESL because 3GIRM itself is not appropriate for THESL.

b)

i. Please also see the response to a) above. Conceptually, it would be possible to devise an IRM that comprised cost drivers beyond simply inflation and productivity. Notably, these cost drivers would include non-revenue producing capital investments in excess of depreciation for the purpose of infrastructure renewal, as well as the incremental operating expenditures in real terms (i.e., apart from inflation) driven by the non-capital costs associated with long-term workplans and workforce renewal.

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To the extent that these cost drivers could be foreseen over the course of an IRM, their revenue requirement impacts could be built into a programmatic mechanism to determine future revenue requirements. However, under such a system, the primary focus would be on revenue requirement rather than rates per se.

Again conceptually, the revenue requirement for a prospective year could be divided into a base portion to which would be applied the escalation factor arising out of the standard IRM, and one or more 'real growth' portions representing the revenue requirement consequences of approved growth in ratebase and incremental 'real' operating expenditures. Provided that the quantity being determined was revenue requirement rather than rates, both the 'base' and 'real growth' portions could be determined formulaically given a Board-approved trajectory of capital expenditures and real operating expenditures growth. Rates for a given year would then be determined by dividing the resulting total revenue requirement by the approved billing determinants forecast.

Such a system would clearly need to be articulated at a greater level of detail, but THESL believes that it could be implemented with appropriate allowances for flexibility and while leaving the existing balance of risk between shareholders and ratepayers essentially unaltered.

ii. Given that the Board has recently announced both the Renewed Regulatory Framework for Electricity initiative and the postponement of 4GIRM, THESL sees little prospect of having a workable alternative to 3GIRM on one hand

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and cost-of-service on the other in place for 2012. Since 3GIRM is unworkable for THESL for the reasons explained above, THESL has no alternative but to propose that its 2012 rates be based on a cost of service proceeding.

However, in the interim before the development of a 'hybrid' ratemaking approach such as the augmented IRM model described above, THESL is prepared to undertake a multi-year cost of service approach, similar to that proposed and successfully implemented for rate years 2008 and 2009, but this time for a three year period. THESL would produce a three-year forecast of capital and operating expenditures and these would be thoroughly examined in the 2012 proceeding. The two succeeding years would then be subject to simpler and more economical review for conformity to the approved plan. This would offer the prospect of real resource cost savings for all parties and would represent a significant step toward a 'hybrid' ratemaking model, with the main difference being that the revenue requirements for the second and third years would be determined directly instead of under a formulaic or programmatic approach.

c) THESL does not believe that it is alone in the circumstances it faces with respect to infrastructure and workforce renewal. Therefore THESL sees significant value in the Board undertaking a generic consultation, similar in scope to that done for 2006 EDR, and within the context of the Renewed Regulatory Framework for Electricity initiative, for the purpose of developing generally applicable ratemaking approaches that combine the best features of both cost-of-service and IRM. THESL suggests that such a project could be undertaken jointly by the Applications and Policy branches of

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the Board in collaboration with utilities and stakeholders, and that the initial stages of the project could commence in the winter or early spring of 2011. If adequate resources were available from all involved parties, the framework could be in place for utilities to commence applications under that framework as early as January 2012 for rates commencing January 2013.

At a high level, the work of the consultation would be to:

- Define the cost drivers that would be included in the framework as well as those that would be treated externally to it (for example, unforeseen government-mandated program costs)
- Define the 'base' and 'real increase' components of total revenue requirement
- Define the mechanisms that would apply to the escalation of both components
- Define the manner of incorporating billing determinant forecasts and changes to cost allocation and rate design
- Define the filing and other information requirements necessary to implement the framework
- Define any mechanisms that might be considered necessary to balance and/or manage risk and unanticipated events
- Define any eligibility requirements or pre-requisite conditions that would have to exist
- Define the year over year ratemaking algorithm that would result

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INTERROGATORY 10:

Reference(s): K1/ T1/ S1, p. 6

THESL states that demographic, economic conditions and conservation activities are captured in its model by the customer, population, and time trend variables:

a) Please provide further explanation as to how the linear trend variable is developed.

b) The time trend variable has a negative co-efficient. This suggests that as the value of the variable increases, the resulting volume would decrease. Given this relation, how is it appropriate that as economic conditions improve, volume declines?

c) Please provide an alternate scenario excluding the linear trend variable.

d) Please provide an alternate scenario including other economic indicators such as Toronto area real GDP monthly index numbers.

e) THESL states that "one of the significant drivers of these decreases is believed to be the impact of conservation…" Please provide an explanation as to why CDM is captured by an economic variable.

RESPONSE:

a) The trend variables are traditionally used when there is a need to reflect continuous historic growth/decline in a dependant variable. The necessity and reasonability of adding trend variables to THESL class loads regression models were tested for each customer class independently.

   As the first step, class historic loads were analysed on an annual and monthly basis. Based on the analysis, determinations were made on the customer class loads that had been showing a declining trend (residential, GS<50 kW, GS 1-5 MW and Large Users), and which of them appeared to be stable (GS 50-1000 kWh, Street Lighting,

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USL).

Then, based on the load behaviour, a number of linear time trend variables were generated for each customer class. Trend variables were distinguished and defined by the month when a decline started to take place.

Generated trend variables were tested for statistical significance along with other explanatory variables in the regression models for each customer class independently. Based on the results of statistical estimation (trend variables significance in the models and adjusted R^2) "the best-fitted" trend variables were chosen for those customer classes which demonstrated a decline in a recent history: July 2002 for Residential and GS<50 kW, Jan 2007 for GS 1-5 kW and Large Users. For monthly values of the trend variables please refer to Table 1, Exhibit K1, Tab 2, Schedule 1 (Columns 12 and 13).

b) The time trend variable is not meant to directly reflect the impact of improving / worsening economic conditions on loads since it is not a "pure" economic indicator (as opposed to Toronto GDP). The usage of time trend variables implies that the dependent variable exhibits a trend through time which will stay the same for the forecasting horizon, apart the influence of other explanatory variables.

The fact that the trend variable is significant and has a negative coefficient is a statistical proof of the declining tendency in class loads over recent history, which is expected to be in place at least for the forecast horizon based on the slow recovery of economy and conservation activities held in the City of Toronto.

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THESL assesses the appropriateness of all model variables, including trend variables, each time it goes through its forecasting exercises.

c) Table 1 below represents class model estimations with trend variables excluded from the list of explanatory variables (for those customer classes where trend variables were originally used). All other variables were left the same as in the filed forecast. The table contains:

1) Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2) R^2 Adjusted criterion values for each customer class.

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Table 1: Alternative scenario "No trend variable" – regression models by class

Variables	Residential	GS<50 kW	GS 1,000-4,999 kW	Large Users
CDD18 per day	**891,537** (0.0000)	**315,423** (0.0000)	**347,512** (0.0000)	**181,107** (0.0002)
HDD10 per day	**273,320** (0.0000)	**75,571** (0.0000)	**168,027** (0.0000)	**77,779** (0.0000)
Dew	n/a	n/a	**95,024** (0.0004)	**38,053** (0.0104)
Business Days %	n/a	**9,044** (0.0438)	**65,551** (0.0000)	**17,968** (0.0537)
Customer numbers	n/a	**291** (0.0000)	**5,076** (0.0769)	n/a
Population	**- 6,044** (0.0000)	**- 4,167** (0.0000)	n/a	n/a
Trend Jul 2002	Excluded	Excluded	n/a	n/a
Trend Jan 2007	n/a	n/a	Excluded	Excluded
Blackout Dummy	**- 1,230,134** (0.0000)	**- 399,364** (0.0000)	**- 983,830** (0.0000)	**- 327,578** (0.0018)
Intercept	**25,929,213** (0.0000)	**- 4,761,781** (0.1690)	**5,752,640** (0.0018)	**5,293,915** (0.0000)
R^2 Adjusted	**94.3%**	**94.8%**	**78.33%**	**56.7%**

Compared to original regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, all models of the alternative scenario performed worse: R^2-Adjusted is lower and the population variables have negative coefficients.

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Table 2 below represents load forecast values (total system and each customer class separately) produced by the regression models with the linear trend variable excluded. The table also contains values of the originally filed forecast.

Table 2: Alternative scenario "No trend variable" vs filed forecast: loads by class

Customer Class	2010 bridge		2011 test	
	No trend variable scenario	Filed forecast	No trend variable scenario	Filed forecast
Residential, kWh	5,268,533,599	5,204,479,464	5,275,692,756	5,174,271,175
GS<50 kW, kWh	2,298,276,081	2,269,627,086	2,268,490,976	2,219,756,435
GS 50-1000 kW, kWh	10,333,984,694		10,496,749,821	
GS 1-5 MW, kWh	5,131,852,411	4,900,491,561	5,243,136,378	4,800,900,765
Large Users, kWh	2,608,609,300	2,493,975,082	2,636,941,001	2,421,224,078
Street Lighting, kWh	113,721,306		114,307,220	
USL, kWh	58,057,651		58,345,893	
Total Purchased Energy, kWh	**25,813,035,043**	**25,374,336,844**	**26,093,664,045**	**25,285,555,387**
Note 1. Loads are before losses				

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Total Purchased Energy forecast for the test 2011 year under this scenario is almost at the level of 2008 historic THESL load on a weather-normalized basis (refer to Table 1 Exhibit K1, Tab 1, Schedule 1, Page 1) which THESL does not believe is appropriate: in the recent years THESL's load experienced a significant decline, and THESL has not seen a steady load recovery yet.

d) As no specific directions were provided on which economic variables to use (except for Toronto GDP), and whether to keep trend variables or not, two alternative scenarios were run.

In the first scenario a GDP variable was added to the original set of explanatory variables (for those customer classes where GDP variable is applicable).

A second scenario was built excluding trend variables and replacing them with Toronto GDP variable where applicable. For the 50-1000 kW customer class the specification for this scenario is the same as for the first scenario as no trend variable was originally used in the filed forecast for this customer class.

I. Alternative scenario I: Toronto GDP added as a variable to the original set of explanatory variables

Table 3 below represents class models estimations with GDP variable added to the original set of variables. The table contains:

1) Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2) R^2-Adjusted values for each customer class.

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Table 3: Alternative scenario "Toronto GDP added" regression models by class

Variables	Residential	GS<50 kW	GS 50-999 kW	GS 1,000-4,999 kW	Large Users
CDD18 per day	**852,573** (0.0000)	**293,739** (0.0000)	**881,222** (0.0000)	**318,656** (0.0000)	**175,304** (0.0001)
HDD10 per day	**279,585** (0.0000)	**77,653** (0.0000)	**435,265** (0.0000)	**159,404** (0.0000)	**67,650** (0.0000)
Dew	n/a	n/a	**111,001** (0.0000)	**90,006** (0.0000)	**30,979** (**0.0171**)
Business Days %	n/a	**8,998** (0.0083)	**44,722** (0.0000)	**60,559** (0.0000)	**14,003** (**0.0923**)
Customer numbers	n/a	**100** (0.0120)	**83** (0.431)	**4,374** (0.2505)	n/a
Population	**6,539** (**0.0336**)	**950** (0.2638)	n/a	n/a	n/a
Blackout Dummy	**- 1,175,797** (0.0000)	**- 297,658** (0.0000)	**- 1,595,183** (0.0000)	**- 934,433** (0.0000)	**- 436,850** (0.0000)
Trend Jul 2002	**- 27,280** (0.0001)	**- 18,759** (0.0000)	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	**- 32,042** (0.0000)	**- 11,679** (0.0002)
Intercept	**915,287** (0.8800)	**- 5,278,137** (0.0741)	**14,953,554** (0.0000)	**3,170,790** (0.0092)	**6,397,569** (0.0000)
Toronto GDP	**- 4** (0.6290)	**14** (0.0000)	**26** (0.0000)	**17** (0.0016)	**- 3** (0.4067)
R^2 Adjusted	**95.1%**	**97.1%**	**96.9%**	**94.00%**	**68.5%**

Compared to original regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, the R^2-Adjusted are comparable for Residential, GS

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50- 999kW, GS 1,000-4,999 kW and Large Users classes and higher for the GS<50 kW class. However, for two classes – Residential and Large Users the GDP coefficient is highly insignificant and negative. For the GS<50 kW, GS 50- 999kW, GS 1,000-4,999 kW classes the inclusion of GDP makes the customer numbers or population insignificant.

Table 4 below represents load forecast values (total system and each customer class separately) produced by the regression models with the GDP variable added to the original set of variables. The table also contains values of the originally filed forecast.

Table 4: Alternative scenario “Toronto GDP added” vs filed forecast: loads by class

Customer Class	2010 bridge		2011 test	
	“Toronto GDP added” scenario	Filed forecast	“Toronto GDP added” scenario	Filed forecast
Residential, kWh	5,205,749,931	5,204,479,464	5,168,762,564	5,174,271,175
GS<50 kW, kWh	2,266,712,047	2,269,627,086	2,238,108,948	2,219,756,435
GS 50-1000 kW, kWh	10,297,658,911	10,333,984,694	10,487,629,913	10,496,749,821
GS 1-5 MW, kWh	4,905,613,970	4,900,491,561	4,843,130,214	4,800,900,765
Large Users, kWh	2,495,128,629	2,493,975,082	2,418,921,649	2,421,224,078
Street Lighting, kWh	113,721,306		114,307,220	
USL, kWh	58,057,651		58,345,893	
Total Purchased Energy, kWh	**25,342,642,444**	**25,374,336,844**	**25,329,206,401**	**25,285,555,387**

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Based on the models statistics shown above, the suggested modification is questionable for all classes. At the same time total Purchased Energy forecast for the test year is not significantly higher than the originally filed forecast.

Alternative scenario II: Trend variables were replaced with Toronto GDP (where applicable); all other variables left the same.

Table 5 below represents class models estimations with trend variables replaced by GDP variable (Residential, GS<50 kW, GS 1-5 MW and Large Users). For the GS 50-1000 kW customer class, GDP was added to the original set of variables as no trend was used for this customer class in the filed forecast. The table contains:

1) Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2) R^2-Adjusted values for each customer class.

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Table 5: Alternative scenario "Trend variables replaced with Toronto GDP" regression models by class

Variables	Residential	GS<50 kW	GS 50-999 kW	GS 1,000-4,999 kW	Large Users
CDD18 per day	**890,402** (0.0000)	**316,778** (0.0000)	**881,222** (0.0000)	**330,628** (0.0000)	**187,315** (0.0000)
HDD10 per day	**274,147** (0.0000)	**74,893** (0.0000)	**435,265** (0.0000)	**174,662** (0.0000)	**68,729** (0.0000)
Dew	n/a	n/a	**111,001** (0.0000)	**100,958** (0.0000)	**31,254** (**0.0146**)
Business Days %	n/a	**9,583** (0.0218)	**44,722** (0.0000)	**65,155** (0.0000)	**15,210** (**0.1268**)
Customer numbers	n/a	**259** (0.0000)	**83** (**0.431**)	**28,050** (0.0003)	n/a
Population	**- 4,580** **(0.0026)**	**- 5,341** (0.0000)	n/a	n/a	n/a
Blackout Dummy	**- 1,269,973** (0.0000)	**- 370,287** (0.0000)	**- 1,595,183** (0.0000)	**- 1,071,026** (0.0000)	**- 490,590** (0.0000)
Trend Jul 2002	Excluded	Excluded	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	Excluded	Excluded
Intercept	**24,921,896** (0.0000)	**- 1,567,601** (0.6588)	**14,953,554** (0.0000)	**786,193** (0.7402)	**8,003,535** (0.0000)
Toronto GDP	**- 10** **(0.2843)**	**7** (0.0290)	**26** (0.0000)	**- 32** (0.0006)	**- 12** (**0.0002**)
R^2 Adjusted	**94.3%**	**95.0%**	**96.9%**	**80.87%**	**61.9%**

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Compared to original regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, all models of the alternative scenario have lower R^2-Adjusted except for the GS 50-999 kW class.). The GDP coefficient turned out to be either insignificant or has unreasonable negative coefficients for Residential, GS 1,000-4,999 kW and Large Users classes. Additionally, the inclusion of GDP variable made population, customer numbers and business days percent variables insignificant or unreasonable (negative coefficients) for certain classes (including GS 50-999 kW).

All the above suggests that the requested modification is not producing models statistically appropriate for building the load forecast. Nevertheless, the load forecast outcome is still provided for the sake of completeness. Table 6 below represents load forecast values (total system and each customer class separately) produced by the regression models with trend variables being replaced by GDP variable.

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Table 6: Alternative scenario "Trend variables replaced with Toronto GDP" vs filed forecast: loads by class

Customer Class	2010		2011	
	"Toronto GDP instead of Trend" scenario	Filed forecast	"Toronto GDP instead of Trend" scenario	Filed forecast
Residential, kWh	5,268,398,764	5,204,479,464	5,257,047,885	5,174,271,175
GS<50 kW, kWh	2,300,279,970	2,269,627,086	2,283,113,601	2,219,756,435
GS 50-1000 kW, kWh	10,297,658,911	10,333,984,694	10,487,629,913	10,496,749,821
GS 1-5 MW, kWh	5,065,479,106	4,900,491,561	5,056,832,973	4,800,900,765
Large Users, kWh	2,569,535,355	2,493,975,082	2,546,407,247	2,421,224,078
Street Lighting, kWh	113,721,306		114,307,220	
USL, kWh	58,057,651		58,345,893	
Total Purchased Energy, kWh	**25,673,131,062**	**25,374,336,844**	**25,803,684,732**	**25,285,555,387**

e) THESL did not state that CDM impact was captured by the economic variables in THESL regression models. Trend variables are not pure economic indicators (such as GDP), but constructed integer variables incorporating time trends into the models. They are aimed to capture and reflect an ongoing decline in loads evident for certain customer classes. Built as a linear time trend this variable indirectly incorporates various factors contributing to the ongoing load decrease. THESL believes that among these factors, recent economic decline as well as ongoing and growing conservation activity are the most crucial to load behaviour. Therefore, by having significant trend variables included in the set of explanatory variables, THESL ensures that the impact of those factors is being captured in the forecast.

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INTERROGATORY 11:

Reference(s): K1/ T1/ S1, p. 6

THESL states that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point".

a) The acceptable standard for HDD for both electricity distributors as well as gas distributors is a balancing point of 18 degrees Celsius. Please provide further evidence supporting a change of this standard to 10 degrees Celsius.

b) Does a reduction of the balancing point from 18 degrees Celsius to 10 degrees Celsius effectively lower THESL's load forecast?

c) Please re-run the load forecast using the standard HDD 18 degrees Celsius in the regression model and subsequent regression equation.

RESPONSE:

a) THESL accepts that HDD based on 18 degrees Celsius has been the "norm" for certain purposes. However, in developing its load forecast, THESL is interested in developing the best statistical relationships between observed variables and loads. Depending on the service area, the load-temperature relationship may have changed over time due to the improving technology, change in insulation standards, housing stock and energy end-users behaviour. Therefore THESL did not feel obligated to use conventional degree days for forecasting purposes when a transparent alternate formulation was available that was statistically superior.

Prior to developing its load forecasting models THESL did research on the degree day calculation issue, including communicating with meteorological services as well

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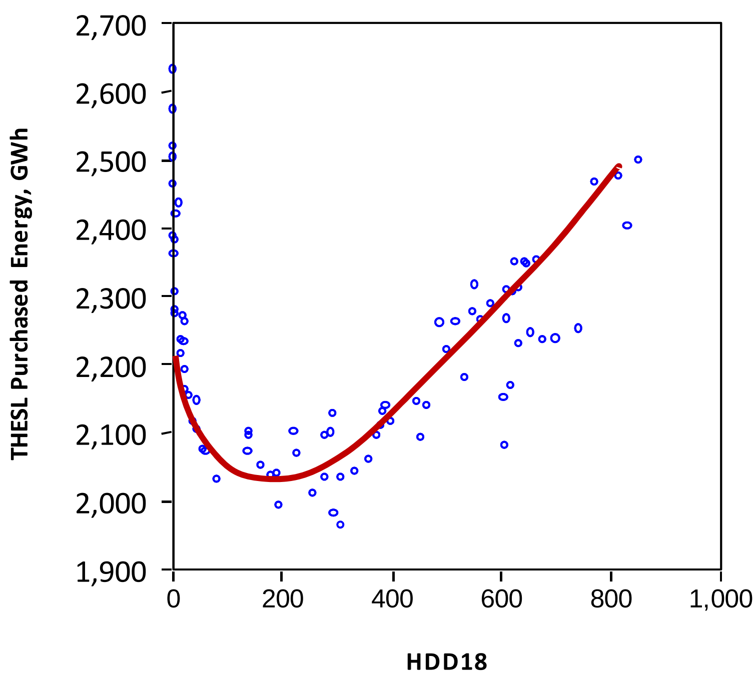
as discussing the issue at load forecasting conferences. Based on the information collected, THESL believed that it was reasonable to question whether HDD based on the 18 degrees Celsius balance point is an accurate reflection of weather-related load patterns.

The THESL load-temperature relationship presented on the graph in Exhibit K1, Tab 1, Schedule 1, page 7 of the filed evidence clearly illustrates that, on average the heating portion of Toronto's load starts to grow when temperatures fall below 10 degrees, not 18 Degrees. Also, as the graphs below illustrate, HDD10 is more suitable for use in linear regression as the HDD10-load relationship has a linear shape. On the contrary, the HDD18-load relationship, at lower values, forms a parabolic-type curve, which will negatively affect its performance in linear regression models.



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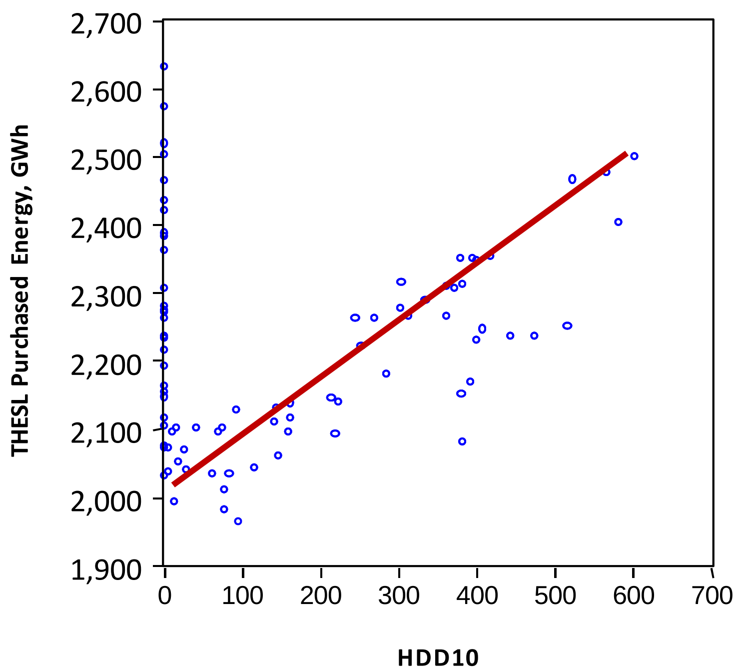

Based on the preliminary analysis of its loads, THESL chose a set of HDD and CDD balance point temperatures, and statistically tested their performance in customer class regressions (as stated on page 7 of Exhibit K1, Tab 1, Schedule 1 of the filed evidence).

The results enabled THESL to confirm that CDD18 still properly reflected the cooling portion of the load-temperature relationship, whereas the results suggest that the HDD balance temperature should be shifted from 18 to 10 Degree Celsius for better modeling of class loads.

b) A load forecast produced based on HDD18 is slightly higher (by 0.5%) than the filed forecast. For more detailed comparison and models statistics for HDD18 scenario please refer to question 11 c) below.

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c) Table 1 below represents class models estimations with HDD 10 replaced by standard HDD18 degree Celsius where applicable. The table contains:

1) Coefficient estimations and probabilities to reflect their significance/insignificance (in brackets below each estimation).
2) R^2-Adjusted values for each customer class.

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Table 1: Alternative scenario "HDD18 instead of HDD10" regression models by class

Variables	Residential	GS<50 kW	GS 50-1000 kW	GS 1-5 MW	Large Users
CDD18	**1,136,948** (0.0000)	**369,247** (0.0000)	**1,250,403** (0.0000)	**452,224** (0.0000)	**237,395** (0.0000)
HDD18 (instead of HDD10)	**220,553** (0.0000)	**60,057** (0.0000)	**376,779** (0.0000)	**136,754** (0.0000)	**50,137** (0.0020)
Dew	n/a	n/a	**152,829** (0.013)	**104,079** (0.0001)	**28,599** (0.1004)
Business Days %	n/a	**6,963** (**0.1860**)	**39,518** (0.051)	**58,734** (0.0000)	**12,615** (0.1472)
Customer numbers	n/a	**183** (**0.0018**)	**525** (0.0000)	**15,107** (0.0000)	n/a
Population	**1,354** **(0.7041)**	**414** (**0.7473**)	n/a	n/a	n/a
Trend Jul 2002	**- 16,580** **(0.0420)**	**- 11,778** (**0.0002**)	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	**- 27,014** (0.0000)	**- 12,691** (0.0000)
Blackout Dummy	**- 1,228,627** (0.0000)	**- 390,754** (0.0000)	**- 1,869,653** (0.0000)	**- 1,022,573** (0.0000)	**- 415,546** (0.0001)
Intercept	**9,647,899** **(0.1893)**	**- 7,061,344** **(0.1061)**	**13,768,656** (0.0000)	**714,568** (0.6366)	**5,641,453** (0.0000)
R^2 Adj	**94.4%**	**93.6%**	**89.1%**	**88.6%**	**64.6%**

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Compared to the filed regression models provided in Exhibit K1, Tab 2, Schedule 2, pages 1-3 of the filed evidence, all models of the alternative HDD18 scenario performed worse: R^2 Adjusted declined for all customer classes. Additionally, the usage of HDD18 instead of HDD10 made other variables (population, business days per cent and dew point temperature) insignificant for certain classes. This supports THESL's decision to calculate Heating Degree Days based on the break point of 10C as a variable better reflecting load-weather relationship.

Table 2 below presents load forecast values (total system and each customer class separately) produced by the regression models with the HDD10 variable replaced by HDD 18 where applicable.

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Table 2: Alternative scenario "HDD18 instead of HDD10" vs filed forecast: loads by class

Customer Class	2010 bridge		2011 test	
	"HDD18 instead of HDD10" scenario	Original model outcome (HDD 10)	"HDD18 instead of HDD10" scenario	Original model outcome (HDD 10)
Residential, kWh	5,230,229,496	5,204,479,464	5,220,853,362	5,174,271,175
GS<50 kW, kWh	2,278,103,413	2,269,627,086	2,232,889,545	2,219,756,435
GS 50-1000 kW, kWh	10,360,494,881	10,333,984,694	10,538,940,476	10,496,749,821
GS 1-5 MW, kWh	4,911,670,946	4,900,491,561	4,820,979,041	4,800,900,765
Large Users, kWh	2,496,733,248	2,493,975,082	2,426,651,104	2,421,224,078
Street Lighting[1], kWh	113,721,306		114,307,220	
USL[1], kWh	58,057,651		58,345,893	
Total Purchased Energy, kWh	**25,449,010,941**	**25,374,336,844**	**25,412,966,642**	**25,285,555,387**

[1] HDD variable modification is not applicable

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INTERROGATORY 12:

Reference(s): K1/ T3/ S1, p. 1

Table 1 Note 1 indicates that THESL has applied a loss factor to convert purchased energy to billed energy by class. Please provide details of this conversion including the loss factor used.

RESPONSE:

Note 1 for Table 1 Exhibit K1, Tab 3, Schedule 1 states that losses were applied to the class loads to convert purchased energy by class to sales by class. To perform these calculations the OEB-approved loss factors were used for each customer class. Table 10-1 below represents Loss Factors by customer class used for the calculation:

Table 10-1: Customer class loss factors applied to convert purchased energy to sales by class

Residential	GS<50 kW	GS 50-999 kW	GS 1,000-4,999 MW	Large Users	Street Lighting	USL
1.0376	1.0376	1.0376	1.0376	1.0187	1.0376	1.0376

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INTERROGATORY 13:

Reference(s): K1/ T1/ S1, p. 10

THESL states that the forecast of customers for the residential sector in 2010 through 2011 includes residential growth resulting from suite metering activity (installation of suite meters in new condominium suites, as well as the conversion of some condominiums from bulk-metered to individual suite-metering).

a) Please provide the percentage of new individually-metered condominium suites versus suites converted from bulk-metering to individual metering.

b) Provide an estimate of how many bulk meters are added each year.

c) Provide an estimate of how many individually-metered suite meters result from a bulk meter.

d) Please provide a customer count forecast excluding the individual suite meters.

RESPONSE:

a) The 2011 residential forecast includes a forecast of **1,500 retrofit** and **3,715 new construction** installations (annual, incremental amounts). This implies the following percentage of retrofits and new construction in the total amount of installations in 2011:

Percentage of individually metered suites converted from bulk-metered condo (retrofits) in the total number of expected individually-metered suites	29%
Percentage of new individually-metered suites (new construction) in the total number of expected individually-metered suites	71%

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b) The number of new bulk or check meters installed at condominiums varies according to developer requests. For THESL suite metering projects it has recently been approximately 22 per year.

c) The number of individually-metered suites resulting from a bulk meter conversion may vary anywhere from 20 to 300 suites depending on the size of the condominium, but would typically be about 175 suites.

d)

	A	B	C=B-A
Year	Individually-Metered Suites (active accounts) (cumulative year-end)	Residential Customers Forecast (including individually metered suites) (year-end)	Residential Customers Forecast excluding individually-metered suites (year-end)
2010	15,942	619,119	603,177
2011	22,101	626,341	604,240

Please note that column A in the table above as well as numbers shown in part (a) only summarize recent THESL Suite Metering Program projections for installations and conversions. These activities result in significant increase of residential class customer numbers and therefore they are treated separately during the development of the forecast. The rest of THESL's individually metered customers are treated as conventional residential customers for the purposes of residential customer numbers forecast. They are included at the column C customer count.

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INTERROGATORY 14:

Reference(s): I1/ T1/ S1/pp. 2-5

THESL has forecast a decline in Other Income from $3.6 million in the 2009 historical year to zero in the 2011 Test year, while forecasting $5.5 million in the 2010 Bridge year.

On page 3 THESL states that "THESL earns revenue by providing services to customers and third parties, gains on the sale of scrap metal, and earns interest income from short-term investments of its idle cash balances".

Please break down these components of Other Income to demonstrate how the three factors referenced above have contributed to Other Income. Please provide this breakdown for the 2006 to 2009 Historical years, the 2010 Bridge and 2011 Test years. Please include:

a) the amount of any gains on the sales of scrap metal as well its book value at the time of sale. Please include the actual revenues earned to date from the sales of scrap metal for the 2010 Bridge year.
b) the level of available cash for short-term investment.
c) revenue earned by providing services to customers and third parties including revenue and expenses from Merchandise and Jobbing for the past five historic years.
d) an explanation as to why Other Income is dropping from $5.5 million in the 2010 Bridge year to zero in the 2011 Test year.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

RESPONSE:

Table 1: Revenue Offsets - Other Income ($ millions)

	Col. 1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7
		2006 Historical	**2007 Historical**	**2008 Historical**	**2009 Historical**	**2010 Bridge**	**2011 Test**
1	Customer Services, net	$0.7	$7.8	$1.1	$2.1	$0.0	$0.0
2	Sale of Scrap Materials, net	$2.0	$3.2	$2.7	$1.2	$0.0	$0.0
3	Interest Income	$11.2	$8.2	$6.0	$1.0	$0.0	$0.0
4	Gain/(Loss) on Disposals	$0.6	$0.5	$0.1	$0.0	$5.5	$0.0
5	Foreign Exchange Gain/(Loss)	$0.4	($0.7)	$0.4	($0.7)	$0.0	$0.0
6	**Total**	$14.9	$19.0	$10.3	$3.6	$5.5	$0.0

a) Book values for scrap metals are not maintained as the ledgers and processes are not designed to maintain details at that level. The related amounts represent sales less costs incurred for recovery and disposition. Actual sales as at September 30, 2010 are $2.2 million.

b) Please refer to response to BOMA Interrogatory 43 (b). Also refer to Exhibit B1, Tab 7, Schedule 1 Pro-forma financial statements for the bridge year end expected cash balance.

c) Annual average sales for the historical years have been $11.5 million and related costs have been $8.5 million.

d) THESL is now forecasting investment interest income of $300,000 (see response to BOMA interrogatory 43 (b)). Net revenue from merchandise and jobbing is expected to be zero, as is the net gain from foreign exchange. In 2010, THESL recognized net pre-tax gains from sale of Named Properties, as explained in the response to VECC Interrogatory 15 (b). THESL does not forecast any gains from Named Property sales in 2011. Please also refer to the response to VECC Interrogatory 15 (e).

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INTERROGATORY 15:

Reference(s): C2/T2/S2/pp.2-3

Table 1 on page 2 shows spending in the substation category increasing in the 2011 Test year to $4.2 million from a level of $1.1 million in the 2010 Bridge year.

On page 3, the reason for this increase is stated as being "to support the overall modernization strategy, address capacity, compliance, obsolescence, functionality and normal aging."

Please provide a breakdown of this increase between the above referenced factors and an explanation of the increase within each of the relevant categories.

RESPONSE:

	2011	2010	Comment
Support Modernization Strategy	0.3		
Add Capacity	0.7	0.6	Expansion of the Access Control & CCTV System
Compliance	0.8	0.1	Backflow preventors
Functionality	0.2	0.3	Weed control, for elimination of pesticides/herbicides
Normal Aging	2.5	0.1	Roof Replacement
	4.2	1.1	

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INTERROGATORY 16:

Reference(s): C2/T3/S2/p.3

Table 1 on this page includes a category "Emerging Portfolios" which is shown as increasing from a zero level in 2008 and 2009 to $32 million in the 2010 Bridge year and $20.3 million in the 2011 Test year.

Please provide a breakdown of the referenced 2010 and 2011 amounts.

RESPONSE:

The breakdown for 2010 and 2011 amounts are as follow:

Emerging Portfolios Material Requirements	2010 Bridge Year	2011 Test Year
Standardization	12.9	2.8
Downtown Contingency	5.5	2.9
Worst Performance Feeder	4.1	0.0
Smart Grid Operations	2.1	6.9
Externally Initiated Plant Relocation/Transit City	7.4	3.6
Station System Enhancement	0.0	2.8
Secondary Upgrades	0.0	1.3
Total	32.0	20.3

The material costs only reflect those materials THESL anticipates purchasing to support those Emerging Portfolios. This does not include any material costs attributed to contractors who would purchase those materials themselves as part of the Emerging Portfolios.

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INTERROGATORY 17:

Reference(s): C2/T3/S2/p.5

Table 3 on this page outlines commodity price net changes on a percentage basis for 2009, 2010 and 2011. For wire and cable, there is a zero percent change in 2009, a 12 percent decrease in 2010 and a 4 percent increase in 2011. Similarly, for pole line hardware, there is a zero percent change in 2009, a 12 percent decrease in 2010 and a one percent increase in 2011.

Please provide a year-by-year explanation of these changes for the two referenced categories.

RESPONSE:

Wire and Cable and Pole Line Hardware:

Overall, pricing for both of these categories of commodities in 2009 was flat versus 2008 pricing. RFPs were issued for both of these categories in 2009 resulting in cost savings on approved products of 12%, which included firm pricing for the first 12 months. For 2011, the wire and cable outlook takes into account forecast of increased commodity pricing (particularly on copper). There are price adjustment mechanisms for wire and cable that will incorporate this anticipated fluctuation into the product cost. There is a lower direct commodity impact to pole line hardware and the 1% increase reflects minimal risk to overall pricing.

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INTERROGATORY 18:

Reference(s): C2/T3/S3/pp.8-9

It is stated that:

"Mobile detection technology has been used by many utilities, in particular, Consolidated Edison ("ConEd") in New York City has used it since 2004. They currently own a fleet of 15 mobile detection vehicles and perform 12 complete system scans per year as required by their regulator, the New York Public Service Commission. Feedback received from ConEd and other utilities using this technology is positive."

Table 1 on page 9 shows costs for contact voltage scan as being $4 million in the 2010 Bridge year and $4.4 million in the 2011 Test year.

a) Please state why the New York Public Service Commission requires ConEd to perform 12 complete system scans per year and please identify how many scans THESL is performing.
b) Please elaborate on the nature of the positive feedback THESL has received from ConEd and other utilities including which other utilities THESL has received this feedback from.
c) Please state whether THESL has any comparative costing data from other utilities and if so how the costs incurred by other utilities compare to the costs that THESL is incurring and expecting to incur.
d) Please state whether or not there are other alternatives to mobile detection technology and, if so, whether or not THESL considered such alternatives and why they were not chosen.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

RESPONSE:

a) The report submitted by Con Edison titled *Results of Stray Voltage Tests and Facility Inspections for the Period Beginning January 1, 2009 and Ending on December 31, 2009* to the New York Public Service Commission, stated that in accordance with the New York Public Service Commission's "Order Establishing Rates for Electric Service" issued March 25, 2008 in Case 08-E-0523, Con Edison performed 12 underground system scans using mobile stray voltage detection technology between December 1, 2008 and December 31, 2009.

The State of New York Public Service Commission stated in Case 08-E-0523 that "Because stray voltage is a critical public safety issue, and because testing methods are relatively new, the Commission will take notice of recent developments and will take a more proactive approach than that which was initially proposed by the Company." Further, "For that reason, we order the Company to perform twelve system-wide mobile stray voltage testing sweeps, rather than the eight initially proposed."

THESL is performing four contact voltage scans in all areas of the distribution system where contact voltage can appear as per page 11 of Exhibit C2, Tab 3, Schedule 3.

b) Con Edison's report on Stray Voltage Test and Facility Inspection stated that Con Edison conducted 1200 Quality Assurance checks on Stray Voltage Testing of Underground Distribution Structures, Overhead Distribution Structures, and Municipality Owned Streetlights and found a 95% reliability within ± 10% relative precision level, and was satisfied with established industry sample design criteria.

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Other positive feedback on other utilities that have used the mobile voltage scanning services was of the anecdotal nature.

c) Power Survey Company has been conducting contact voltage scans successfully for major cities in the United States, including New York City. They have proprietary technology that has been proven in the field to be effective and efficient in identifying locations where contact voltage is present. During the 2009 Level III emergency event, they were engaged to conduct a survey of the streets in Toronto. THESL did not receive comparative costing data from other utilities.

d) The only other alternative to mobile detection technology known to THESL is a manual structure-by-structure search for contact voltage using handheld detection devices. The manual detection methods are very labour-intensive and provide unreliable results when a good ground point is not available.

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INTERROGATORY 19:

Reference(s): **D1/T3/S1**
F1/T1/S1
F2/T1/S1
J1/T2/S1

In each of these Exhibits, different presentations of OM&A numbers are provided.

Exhibit D1 provides distribution expenses based on the Board's reporting categories.

Exhibit F1 provides operations and maintenance distribution expenses, while Exhibit F2 provides administration and general expenses. When these numbers are totaled, they are different from the total in Exhibit D1.

Exhibit J1 provides distribution expenses before PILs. These numbers are different from both those of Exhibits F1 and F2 and from Exhibit D1.

a) Please provide a schedule reconciling the differences between these numbers for all years contained in the application.
b) Please provide a breakdown of the drivers of the increases in THESL's OM&A costs in the format of Appendix 2-G of Chapter 2 of the Board's Filing Requirements for the years 2009, 2010 Bridge and 2011 Test.

RESPONSE:

a) Please see Table 1 below.

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Table 1: Reconciliation of OM&A, A&G and Distribution Expenses ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test
O&M Expense[1]	155.9	166.9	179.6	193.3
A&G Expense[2]	68.9	71.7	75.4	83.3
Less: Disallowed A&G Costs	-	-0.4	-0.1	-
Less: Recoveries[3]	-42.4	-43.1	-44.1	-49.8
Subtotal	182.4	195.1	210.8	226.8
Add: Depreciation Expense[4]	149.0	155.5	164.5	178.3
Rounding	0.2	0.1	0.1	-
Distribution Expenses[5]	331.6	350.7	375.4	405.1
Less: Provincial Capital taxes	-8.0	-5.5	-2.1	-
Rounding	-0.1	-0.1	-	-
Distribution Expenses[6]	323.5	345.1	373.3	405.1

Notes:

1) Exhibit F1, Tab 1, Schedule 1
2) Exhibit F2, Tab 1, Schedule 1
3) Recoveries represent the recovery portion of departmental distribution expenses that (i) are charged to other departments, projects or programs. The offsetting charge or cost is then attributed to project or program expenditures. This includes occupancy costs, overhead changes for materials, and fleet costs. This also includes (ii) the amounts reducing departmental expenses for transfers to regulatory assets. For example, the departmental recovery

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amounts that were charged to regulatory assets (i.e. Smart Meter and IFRS program costs) are reflected in this line.

4) Exhibit D1, Tab 13, Schedule 1
5) Exhibit D1, Tab 3, Schedule 1
6) Exhibit J1, Tab 1, Schedule 1

b) Please see Table 2 below.

Table 2: Drivers

	2008 Historical - 2009 Historical	2009 Historical - 2010 Bridge	2010 Bridge - 2011 Test
Opening Balance	182.4	195.1	210.8
Labour	3.3	14.4	10.1
External Services	10.1	2.6	4.1
Materials	(1.7)	5.7	(0.7)
Bad Debts	2.8	(0.9)	0.8
Capital Tax	(2.2)	(3.1)	(1.9)
Others	0.2	(2.9)	3.5
Rounding	0.2	(0.1)	0.1
Closing Balance	195.1	210.8	226.8

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INTERROGATORY 20:

Reference(s): **F1/T1/S1**

Please state whether or not any CDM costs are incorporated for recovery in the 2011 Test year. If there are any such costs, please state the basis on which THESL believes their recovery through rates is appropriate.

RESPONSE:

There are no CDM costs incorporated for recovery in the 2011 Test year.

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INTERROGATORY 21:

Reference(s): F1/T1/S3/p4

It is stated that:

"As is detailed in Exhibit C2, Tab 3 Schedule 3, THESL engages a number of qualified external entities to perform preventative maintenance tasks for several programs. External contractors are engaged to provide these services due to the seasonal nature of the work and the specialized expertise and equipment required. This practice of using external contracts is considered utility best practice in meeting seasonal maintenance requirements."

Please state whether or not THESL's use of external contractors is based on a cost-benefit analysis. If so, please state the amount of annual savings, if not please identify the rationale for outsourcing.

RESPONSE:

No, THESL has not performed a cost-benefit analysis specifically for seasonal contract work. External contractors are used to perform seasonal work because they have specialized skills and can be deployed seasonally, thus saving THESL from purchasing equipment that is limited to seasonal use. THESL internal resources are limited and would not be able to take on these seasonal contracts. The cost of developing and maintaining staff with specific competencies for seasonal use may not be cost-effective.

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INTERROGATORY 22:

Reference(s): F1/T1/S4/p5

It is stated that:

"THESL uses a ten-year inspection cycle for testing and treatment of its 159,000 wood poles."

Please state whether the ten-year inspection cycle is an industry standard and if not, how it was determined.

RESPONSE:

The Canadian Electrical Association does not have any recommendations for a testing cycle for wood poles. Toronto Hydro follows a ten-year inspection cycle because that is the manufacturer specified lifespan of our wood pole remedial treatment chemicals. The chemicals used by Toronto Hydro's pole testing contractor meet or exceed the ten-year lifespan.

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INTERROGATORY 23:

Reference(s): F1/T1/S4/pp. 5-7

It is stated on page 5 that:

"THESL has elected to employ mobile contact voltage scanning technology. Power Survey Company, which owns the rights to the technology, has been selected to perform scans of the distribution system in Toronto…"

On page 7 when discussing the increase in predictive maintenance costs in the 2011 test year, it is stated that "This increase includes a forecasted increase from $4 million to $4.4 million for the Contact Voltage Scan program under external contracts."

a) Please provide a detailed breakdown of these costs.
b) Please describe the process by which Power Survey Company was selected, including whether or not there was a competitive bidding process and, if not, why not.
c) Please state whether or not the decision to hire Power Survey Company was based on any cost/benefit analyses. If so, please provide the results, if not, please explain why not.

RESPONSE:

a) The $4.4 million amount represents the second year of a lump-sum contract to perform contact voltage scanning in the City of Toronto by Power Survey Company. Cost breakdown is not available. The increase from $4 million to $4.4 million is due to anticipated exchange rate difference between Canadian and US dollars. The contact voltage scanning contract is in US dollars.

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b) Power Survey Company has been conducting contact voltage scans successfully in major cities in the United States, including New York City. They have proprietary technology that has been proven in the field to be effective and efficient in identifying locations where contact voltage is present. During the 2009 Level III emergency event, they were engaged to conduct a survey of the streets in Toronto. Their scanning method was found to be much more effective and efficient at identifying the source of contact voltage compared to manual examination of each electrical structure on the street and sidewalks. THESL has engaged the Power Survey Company to perform regularly scheduled contact voltage scans in 2010 with satisfactory results, under a contract that continues in 2011. Competitive bidding was not used because PSC holds the patent to this scanning technology and there is no other comparable technology available in the marketplace to effectively scan large areas.

c) The reasons for selecting Power Survey Company are provided above in response to part b) of this question. A formal cost/benefit analysis was not performed because during the Level III emergency when PSC's services were first employed, it was clearly demonstrated that this was an effective methodology compared to manual methods. In the first city-wide scan, a total of 221 sources of contact voltage were identified and subsequently repaired.

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INTERROGATORY 24:

Reference(s): F1/T1/S6/p3

Table 1 shows an increase in emergency maintenance costs in the 2011 Test year to $7.5 million from $6.6 million in the 2010 Bridge year. This increase is attributed in part to changing weather patterns including more frequent mini-storms and more severe storms.

a) Please state whether the conclusion that changing weather patterns are a factor in this cost increase is based on a study, and if so please file such study, or on THESL's observations and when these changing weather patterns began to impact these costs.

b) Please provide a breakdown of emergency spending costs on an equivalent basis to that of Table 1 for the years 2004 to 2007.

RESPONSE:

a) THESL does not have any climatic analyses/studies that underpins the increase in costs. However, THESL has observed an upward trend of distribution plant damage caused by weather-related incidents from 2005 to 2009 with significant Major Event Days related to weather in 2009. On this basis an increase in 2011 emergency maintenance spending is warranted.

b) A breakdown of emergency spending costs for the years 2006 and 2007 is provided in Table 1 below. The amounts for 2004 and 2005 are not available as the method and process of tracking related information has changed.

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Table 1: Emergency Maintenance Costs ($ millions)

Emergency	2006 Actual	2007 Actual
OH/UG Distribution Assets	6.5	7.5
Station Assets	0.4	0.7
External Contracts	-	-
Total	**6.9**	**8.3**

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INTERROGATORY 25:

Reference(s): F1/T2/S1/p3

Table 1 presents Fleet and Equipment Services ("FES") costs for 2008 and 2009 Historical, 2010 Bridge and 2011 Test years. Please provide these numbers for the years 2004 to 2007.

RESPONSE:

A breakdown of Fleet and Equipment Services ("FES") for the years 2006 and 2007 is provided in Table 1 below. THESL is unable to provide a breakdown of Fleet and Equipment Services for 2004 and 2005 due to its existing method and process for tracking related costs.

Table 1: Operating Expenses for Equipment Services ($ millions)

	2006 Historical	2007 Historical
Total FES Costs	10.8	9.6

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INTERROGATORY 26:

Reference(s): F1/T2/S1/p5

Table 3 presents Laboratory Service Operating Costs for 2008 and 2009 Historical, 2010 Bridge and 2011 Test years. Please provide these numbers for the years 2004 to 2007.

RESPONSE:

A breakdown of Laboratory Services Operating Costs for the years 2006 and 2007 is provided in Table 1 below. THESL is unable to provide a breakdown of Laboratory Services Operating Costs for 2004 and 2005 due to its existing method and process for tracking related information.

Table 1: Laboratory Services Operating Costs ($ millions)

	2006 Historical	2007 Historical
Total Glove Lab	1.4	1.1

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INTERROGATORY 27:

Reference(s): F2/T3/S1/p2 Update November 8, 2010

Table 1: "Charitable Donations Cost" shows an amount for the 2011 Test year of $0.7 million. The covering letter accompanying this update states that "THESL has increased its Charitable Donations amount for 2011 to $0.7 million to reflect direction provided by the Board in its letter dated October 20, 2010 with respect to LEAP Emergency Financial Assistance."

a) Please provide the calculation from which this amount is derived in sufficient detail so that its compliance with the Board's letter can be assessed.
b) If there are departures from the Board's letter, please state what they are and provide a justification for them.
c) Please state whether or not the applicant has included an amount in its 2011 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

RESPONSE:

a) THESL calculated this amount by using the methodology outlined in the Board's October 20, 2010 directive which required that 0.12% of a utility's total (service) distribution revenue requirement be allocated towards LEAP for 2011. In THESL's case, this results in $0.7M ($598.2M x 0.12% = $717,840).

b) There are no departures from the Board's directive.

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c) THESL has not included any amounts in revenue requirement for legacy programs such as Winter Warmth, as LEAP effectively replaces Winter Warmth as of January 1, 2011. While the $0.1M which was included in the pre-filed evidence was originally budgeted for Winter Warmth, THESL has reallocated this amount towards LEAP, such that the entire $0.7M currently requested is exclusively for the LEAP program.

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INTERROGATORY 28:

Reference(s): F2/T3/S1

In this section, charitable contributions are discussed.

Please identify whether or not the applicant has included any charitable or political donations as part of its forecast OM&A expense for the Test Year. If yes, please identify the amounts and the account in which the donations are recorded, and whether the amounts are compliant with Section 2.5.2 of the Filing Requirements.

RESPONSE:

The only charitable contribution is $0.7M towards the LEAP program, which replaces the Winter Warmth program for which the original $0.1M (as included in prefiled evidence) was directed. No other charitable donations or political contributions are included in THESL's forecast OM&A.

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INTERROGATORY 29:

Reference(s): **F2/T5/S1/p1**

Table 1 on this page provides a breakdown of THESL's Finance A&G costs. This table shows total levels of $4.3 million for 2008 Historical, $4.5 million for 2009 Actual, $10.5 million for 2010 Bridge and $15.3 million for 2011Test.

Please break down the Year by year increases into two components: (1) component of the increase related to costs previously charged as THC Shared Services functions recorded in Governance now charged to Finance as part of the reorganization, and (2) remaining component not related to this reorganization and the factors explaining this element of the increase.

RESPONSE:

The $5.4M year over year increase in A&G costs in 2010 Bridge as compared to 2009 Actual is related to the Finance reorganization. When comparing the same group in 2011Test, the increase is due mainly to IFRS and increased support required for financial reporting.

The remaining component not related to the Finance reorganization was relatively flat when comparing 2008 Historical and 2009 Actual. From 2009 Actual to 2010 Bridge, the Finance A&G cost increase is reflective of the additional resources required to support the expanded capital program and related operational and support activities. In 2011 Test, the increase in Controllership A&G cost is due to additional resources required to support increasing financial requirements and the expanded capital program.

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Please see Appendix A for year-over-year increase and explanation.

APPENDIX A

Interrogatory Response

THESL Finance A&G Costs ($ millions)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		2008 Historical	2009 Actual	Increase/(Decrease)	Comments
1	(1) Component Related to Costs Previously Charged as THC Shared Services				
2	External Reporting	0.0	0.0	0.0	
3	Tax & Internal Audit	0.0	0.0	0.0	
4	Total	0.0	0.0	0.0	
5	(2) Remaining Component not Related to Reorganization				
6	Controllership	2.6	2.8	0.2	
7	Accounts Payable & Payroll	1.7	1.7	0.0	
8	Total	4.3	4.5	0.1	
9					
10	TOTAL	4.3	4.5	0.1	

11

12 Table 2

13		2009 Actual	2010 Bridge	Increase/(Decrease)	Comments
14	(1) Component Related to Costs Previously Charged as THC Shared Services				
15	External Reporting	0.0	2.4	2.4	
16	Tax & Internal Audit	0.0	2.9	2.9	
17	Total	0.0	5.4	5.4	
18	(2) Remaining Component not Related to Reorganization				
19	Controllership	2.8	3.4	0.6	Increase is reflective of the additional resources required to support the expanded capital program and related operational and support activities.
20	Accounts Payable & Payroll	1.7	1.8	0.1	
21	Total	4.5	5.2	0.7	
22					
23	TOTAL	4.5	10.5	6.1	

24

25 Table 3

26		2010 Bridge	2011 Test	Increase/(Decrease)	Comments
27	(1) Component Related to Costs Previously Charged as THC Shared Services				
28	External Reporting	2.4	5.8	3.4	As referred to in Exhibit F2/Tab5/S1/p5. Increase is due mainly to IFRS $3.1M, and increase support for required finance reporting.
29	Tax & Internal Audit	2.9	3.1	0.1	
30	Total	5.4	8.9	3.5	
31	(2) Remaining Component not Related to Reorganization				
32	Controllership	3.4	4.5	1.1	As referred to in Exhibit F2/Tab5/S1/p4. Increase is due to additional resources required to support increasing financial requirements and expanded capital program.
33	Accounts Payable & Payroll	1.8	1.9	0.1	
34	Total	5.2	6.4	1.3	
35					
36	TOTAL	10.5	15.3	4.8	

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INTERROGATORY 30:

Reference(s): F2/T6/S1/p3

On this page, the costs for the Treasury, Rates and Regulatory Affairs groups are shown.

a) Please provide a breakdown of THESL's regulatory costs in the format of Appendix 2-H of the Filing Requirements.

RESPONSE:

Please see Appendix A to this Schedule which contains as much of the requested information that THESL has available. THESL prepares many of its regulatory applications with significant input from the Business Units. Operating costs associated with the preparation of pre-filed evidence and interrogatories for example remain co-mingled with the Business Unit operating costs Amounts presented in the table for this cost item are based on a gross estimate the number of people and expected time involvement.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13
Row	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year	Actuals (2007), $	Actuals (2008), $	Actuals (2009), $	Bridge Year (2010) FORECAST, $	% Change in Bridge year vs Last Year of Actuals	Test Year Forecast (2011), $	% Change in Test year vs Bridge year	Comments
1	OEB Annual Assessment			on-going		3,370,539	3,124,221	3,155,604	3,500,000	11%	3,400,000	-3%	
2	OEB Hearing Assessments - Applicant-Initiated			one-time		see note 1	44,907	4,641	0	-100%	see note 2	N/A	
3	OEB Section 30 Costs - OEB-Initiated			on-going		see note 1	17,430	150,888	0	-100%	see note 2	N/A	
4	Expert Witness cost for regulatory matters			one-time		195,742	376,049	85,974	190,000	121%	195,225	3%	
5	Legal costs for regulatory matters			one-time		271,355	263,163	881,605	500,000	-43%	513,750	3%	
6	Consultant costs for regulatory matters			one-time		649,601	314,696	356,526	419,400	18%	430,934	3%	
7	Operating expenses associated with Staff resources allocated to regulatory matters			on-going		1,501,287	1,094,769	1,123,292	1,410,258	26%	1,326,778	-6%	Operating costs associated with the preparation and defense of applications is comingled with the Business Unit operating budgets. The figures here are estimates. The revised (highlighted) cells now include payroll costs for Regulatory Applications & Compliance and Regulatory Policy & Relations Staff only. /C
8	Operating expenses associated with Other Resources allocated to regulatory matters					82,454	16,499	80,316	10,530	-87%	10,820	3%	
9	Other regulatory agency fees or assessments					0	0	0	0		see note 2	N/A	
10	Any other costs for regulatory matters - Annual Registration Fee for THESL's Distribution Licence			on-going		1,888	816	800	21,840	2630%	23,509	8%	
11	Intervenor Costs			on-going		255,046	291,890	120,043	350,000	192%	359,625	3%	
12	Subtotal					6,327,912	5,544,440	5,959,687	6,402,028	7%	6,260,641	-2%	

(1) Note that items 2, 3, 10, 11 are charged to the same expense element. Details from 2007 are difficult to recreate presently. The total amount has been provided in item 11. ($255,046)
(2) Note that items 2, 3, 10, 11 are charged to the same expense element. Information for 2011 represents the total budget for these items. ($359,625)

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 31:

Reference(s): F2/T6/S1/p3

Table 1 includes an item "Short-Term Interest Expenses on Line of Credit and Customer Deposits." This item was zero in 2008 and 2009 increasing to $1.6 million in the 2010 Bridge year and $2.9 million in the 2011 Test year.

When describing the line of credit expense, it is stated that "Due to the recent crisis in short-term credit markets, the market-based fees associated with short-term lines of credit have increased significantly. In the Test year, THESL has forecast fees on the short-term lines to be $2.1 million."

a) Please break down these amounts into the two component items.
b) For the line of credit expense, please provide a detailed explanation as to the reason why these fees are forecast to be $2.1 million. Please also discuss why no fees were paid in 2008 and 2009.
c) Please state whether or not these fees are being included for recovery in the 2011 revenue requirement. If these fees are being included, please explain why they would not be recovered through the 4% short-term debt component of the deemed capital structure.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

RESPONSE:

a)

	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Short-Term Interest Expense – Customer Deposits	-	-	0.8	0.8
Short-Term Interest Expense – Line of Credit	-	-	0.8	2.1

b) Due to the credit crisis in world financial markets, the cost of borrowing for all lenders has increased significantly. THC's banking syndicate's lending costs also increased, and this cost increase was passed on to THC upon the renewal of its short-term lines in May 2010.

THESL did pay fees for maintenance of its line of credit in 2008 and 2009. However, they were much lower, and were not requested for inclusion in revenue requirement in those years and therefore were not included in Table 1.

c) THESL is requesting these fees be included in revenue requirement in 2011. Unlike the short-term debt component, which includes an allowance for financing costs in the calculation of overall cost of debt, there is no mechanism in the current cost of capital guidelines for inclusion of similar costs on short-term debt. The allowed rate on short-term debt does not include these costs, which as demonstrated, have become much more significant in the last two years.

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INTERROGATORY 32:

Reference(s): F2/T7/S1

In this section, Legal Services costs are discussed. Please state whether or not any legal costs related to the late payment penalty settlement process are included for the 2011 Test year.

RESPONSE:

No costs related to the LPP Settlement process have been budgeted for 2011, since that process has substantially concluded. Costs for the EB-2010-0295 proceeding were not specifically included at the time the test year budget was formulated since its existence was not known at that time.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 33:

Reference(s): F2/T9/S1/pp. 4-5

On these pages, external and contract services are discussed. Please provide the following for Historical, Bridge and Test years:

1) Identity of each company transacting with the applicant subject to the applicable materiality threshold
2) Summary of the nature of the product or service that is the subject of the transaction
3) Annual dollar amount related to each company (by transaction)
4) A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.).

RESPONSE:

1) Listed below in Table 1 is each company transacting with THESL, using a threshold of $100K per year. Included in the list are those companies which have transactions exceeding the threshold in at least one of the Historical, Bridge or Test Years. The numbers have been aggregated to avoid any commercial confidentiality breaches.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 1: List of companies transacting with THESL:

Nature of Product or Service	Supplier Name	2008 History ($M)	2009 History ($M)	2010 Bridge ($M)	2011 Test ($M)
Communication Providers	• Bell Canada • Cogeco • Harjevic • IBM • Industry Canada • Rogers Wireless	1.22	1.04	1.60	1.36
Consulting Service Providers	• Deloitte • Dencot Holding 2000 Inc • Extensys • IBM Canada Ltd • Ilantus • Millennium Care • Navigant • SBR • Tenet	1.58	1.20	0.54	0.45
Hardware Maintenance	• Cisco • Dell • Elster Metering • EMC Corporation of Canada • Hewlett Parkard Canada • IBM Canada Ltd • Intercon Security Ltd • Netezza • Oracle Corporation Canada	0.89	1.44	1.45	1.62

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Nature of Product or Service	Supplier Name	2008 History ($M)	2009 History ($M)	2010 Bridge ($M)	2011 Test ($M)
Staff Augmentation Providers	• Afsan Service Inc. • Compu-Source Staffing • CSI Consulting Inc. • Infotek Consulting Service Inc. • Integrated Voice Service Inc. • Procom Services • PTC Accounting • Quantum Technology Recruiting • Sapphire Technologies Canada	2.80	4.41	4.86	3.69
Outsourcing Services	• Millennium Care • Kubra Data Transfer Ltd • Unisys Canada Inc	1.27	0.10	0.15	1.27

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Nature of Product or Service	Supplier Name	2008 History ($M)	2009 History ($M)	2010 Bridge ($M)	2011 Test ($M)
Software Maintenance Service	• Bentley • BMC Software Canada • Compuware Corporation of Canada • Devonway • Emergent • Emeter • Hewlett Packard Canada • Hyperion • Information System Architects • Integraph Canada Ltd • Itron • Mincom • Novell Canada • Oracle Corporation Canada • Redhat Inc. • Redprairie Corporation • SAP Canada Inc • The Herjavec Group • Whitecap Canada Inc	2.54	3.27	4.39	4.43

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

2) Listed above in Table 1 is the summary of the nature of the product or service that is the subject of the transaction.

3) Listed above in Table 1 is the annual dollar amount related to each product or service.

4) IT&S follows the THESL procurement policy, as per Exhibit C2, Tab 3, Schedule 1, Appendix A.

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INTERROGATORY 34:

Reference(s): **F2/T10/S1/p. 4**

It is stated that:

"Given the unprecedented level of recruitment and an increased level of labour relations activity, it was decided in late 2009 to separate staffing and labour relations, thereby ensuring talent acquisition was not overshadowed by urgent labour needs."

a) Please state how THESL reached the decision to undertake this separation e.g. was it based on a study, and if so please state who conducted the study and summarize its key conclusions.
b) Please state whether there were any additional costs arising from this decision, either on a one-time or incremental basis.

RESPONSE:

a) No study was conducted. Due to THESL's workforce renewal plan, the volume of recruitment has increased by approximately 400% from previous years. This level of recruitment along with continued labour relations activity could not be sustained under the former structure while retaining the same number of FTEs. To ensure appropriate focus and effort in both areas, the decision was made to separate the two functions of staffing and labour relations.

b) Additional costs arose from an increase in FTEs for the staffing function.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 35:

Reference(s): F2/T10/S1/pp. 5-6

It is stated that:

"The infrastructure plan will result in unprecedented numbers of contractors working on THESL's equipment and facilities. Many of them will be unfamiliar with the system's unique risks and therefore, will place additional pressures on the requirements to manage safety. A priority is to reinforce existing EHS Programs and work procedures and ensure this workforce is properly trained to work safely and efficiently on THESL's distribution system."

a) Please provide more details as to how THESL will ensure that this work force is properly trained and provide a breakdown of the anticipated costs.
b) Please state whether this aspect of the infrastructure plan is anticipated to have any impact on the reliability of the distribution system.

RESPONSE:

a) Prior to being awarded an RFP, the contractor undergoes an extensive review of their health and safety programs, including training records and certificates. Only those contractors meeting THESL's requirements are hired. A condition of being awarded an RFP is to be enrolled, or commit to be enrolled, in a recognized safety management system (e.g., ZeroQuest, CSA Z1000, ANSI Z10, OHSAS 18001) that is audited by an independent third party auditor. All such safety management systems contain risk based health and safety training as an element that is subject to audit.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Once the RFP is issued, additional checks are made to verify the competencies of all individuals assigned to work at THESL. Prior to commencing work on THESL equipment, the approved contractors must attend an orientation of one to 4.5 days depending on the risk exposure. Additional training for confined space entry, a high risk operation, specific for THESL's risks and protocols has been developed in conjunction with the Infrastructure Health and Safety Association (IHSA) and made mandatory for all contractors doing confined space entry. This training is conducted by IHSA. Additional pre-qualification requirements have been established for contractors requiring confined space access that includes an assessment of the contractor's training program and equipment.

Bi-weekly meetings are held with the affected contractors to cover safety and any lessons learned.

A disciplinary process is in place for contractors contravening safety rules and procedures.

THESL supervisors and managers conduct regular safety inspections of the contractors to ensure safe practices are followed.

Employees have been empowered under the Internal Responsibility System (IRS) to report contractors they observe contravening safe practices.

No additional costs are incurred by THESL. Activities and associated materials, such as course material, are part of day-to-day operational costs. The delivery and cost of

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

training for confined space entry, rescue, first aid, WHMIS, Transportation of Dangerous Goods, etc. are the responsibility of the contractor.

b) This aspect of the infrastructure plan is anticipated to improve system reliability. When workers are properly trained, fewer accidents or injuries occur that would require work to stop so that the injured worker can be treated and the incident investigated. Serious cases may require the all or part of the grid to be de-energized to exercise an appropriate response or conduct the investigation. The immediate effect is a less reliable supply to the customer. The longer term effect may be delays in upgrading the infrastructure while crews are deployed to incident investigation.

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INTERROGATORY 36:

Reference(s): F2/T10/S1/pp. 8-9

Table 4 "Organizational Development & Performance Costs" shows an increase in these costs to $4.8 million in the 2011 Test year from a constant level of $2.8 million in the two most recent historical years of 2008 and 2009. Table 5 provides an explanation of the reasons for this increase.

Please provide a breakdown of the $2 million increase between the explanatory factors outlined in Table 5.

RESPONSE:

$.9M: Additional FTEs hired when trades and technical training was centralized in ODP to support workforce renewal; a new portfolio for employee engagement; and an increase in mandatory and legislative/compliance training. Centralization of this training reduces the need to draw employees away from capital work to deliver training.

$1.1M: Accelerated requirements for driver training mandated by the MTO ($400k), increased demand for legislative and mandatory trades-related training ($300k); partnership with Georgian College to advance utility-based trades and technical curriculum for future hiring and to upgrade technical and trades training of current employees ($150k); advancement of leadership programs to manage a changing workforce; training for harmonized jobs; technology skills development; and programs to facilitate knowledge transfer of retiring employees ($250k).

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 37:

Reference(s): **C1/T3/S1**

Please complete the following table for 2009 Historical, 2010 Bridge and 2011 Test years for each service provided or received by THESL:

RESPONSE:

Year: 2009

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THC	THESL	Governance	Time Study Basis	0.92	0.92	39.84
THC	THESL	Finance	Time Study Basis	7.13	7.13	66.33
THC	THESL	Organizational Effectiveness & EHS	Time Study Basis	0.43	0.43	31.54
THC	THESL	Legal	Time Study Basis	0.73	0.73	55.46
THC	THESL	Communications & Public Affairs	Time Study Basis	0.23	0.23	23.64
THESL	TH Energy	Procurement	No. of purchase orders	0.08	0.08	9.90
THESL	TH Energy	Facilities	Sq. footage	0.04	0.04	0.16
THESL	TH Energy	Finance	No. of invoices, Headcount	0.08	0.08	2.71

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Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THESL	TH Energy	Treasury	% of work performed, FTEs, % of insurance	0.41	0.41	3.37
THESL	TH Energy	Legal	Driver billable hours	0.06	0.06	2.24
THESL	TH Energy	Communications	% of work performed, FTEs	0.10	0.10	2.52
THESL	TH Energy	ITS & Management	By employee and by type of equipment, directly attributable costs	0.57	0.57	2.48
THESL	TH Energy	Environmental, Health, & Safety	Headcount	0.08	0.08	2.27
THESL	THC	Procurement	No. of purchase orders	0.02	0.02	1.96
THESL	THC	Facilities	Sq. footage	0.55	0.55	2.10
THESL	THC	Finance	No. of invoices, Headcount	0.03	0.03	1.00
THESL	THC	Treasury	% of work performed, FTEs, % of insurance	0.62	0.62	5.10
THESL	THC	Organization Effectiveness	Headcount	0.20	0.20	2.91

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THESL	THC	Legal	Driver billable hours	0.02	0.02	0.59
THESL	THC	Communications	% of work performed, FTEs	0.25	0.25	6.48
THESL	THC	ITS & Management	By employee and by type of equipment, directly attributable costs	0.48	0.48	2.10
THESL	14 Co.	Treasury	% of work performed, FTEs	0.02	0.02	0.14

Year: 2010

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THC	THESL	Governance	Time Study Basis	1.66	1.66	75.70
THC	THESL	Finance	Time Study Basis	0.74	0.74	90.64
THC	THESL	Organizational Effectiveness & EHS	Time Study Basis	0.00	0.00	0.00
THC	THESL	Legal	Time Study Basis	0.00	0.00	0.00

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THC	THESL	Communications & Public Affairs	Time Study Basis	0.00	0.00	0.00
THESL	TH Energy	Procurement	No. of purchase orders	0.15	0.15	7.25
THESL	TH Energy	Finance	Audit fees split, no. of invoices, headcount, % of work performed, directly attributable costs	0.30	0.30	2.45
THESL	TH Energy	Treasury	% of work performed, FTEs, % of insurance	0.05	0.05	0.41
THESL	TH Energy	Organization Effectiveness	Headcount, % of work performed	0.05	0.05	0.58
THESL	TH Energy	Legal	Driver billable hours, % of work performed	0.10	0.10	2.24
THESL	TH Energy	ITS & Management	By employee and by type of equipment, directly attributable costs	0.45	0.45	1.43

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THESL	TH Energy	Environmental, Health, & Safety	Headcount	0.05	0.05	1.31
THESL	THC	Facilities	Sq. footage	0.08	0.08	0.31
THESL	THC	ITS & Management	By employee and by type of equipment	0.03	0.03	0.09
THESL	14 Co.	Treasury	% of work performed, FTEs	0.01	0.01	0.10

Year: 2011

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THC	THESL	Governance	Time Study Basis	1.18	1.18	64.47
THC	THESL	Finance	Time Study Basis	0.79	0.79	91.84
THC	THESL	Organizational Effectiveness & EHS	Time Study Basis	0.00	0.00	0.00
THC	THESL	Legal	Time Study Basis	0.00	0.00	0.00
THC	THESL	Communications & Public Affairs	Time Study Basis	0.00	0.00	0.00
THESL	TH Energy	Procurement	No. of purchase orders	0.16	0.16	7.42

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THESL	TH Energy	Consolidated Billing	% of work performed	0.27	0.27	99.00
THESL	TH Energy	Finance	Audit fees split, no. of invoices, headcount, % of work performed, directly attributable costs	0.48	0.48	3.23
THESL	TH Energy	Treasury	% of work performed, FTEs, % of insurance	0.06	0.06	0.46
THESL	TH Energy	Organization Effectiveness	Headcount, % of work performed	0.05	0.05	0.53
THESL	TH Energy	Legal	Driver billable hours	0.06	0.06	1.63
THESL	TH Energy	ITS & Management	By employee and by type of equipment	0.06	0.06	0.19
THESL	TH Energy	Environmental, Health, & Safety	Headcount	0.03	0.03	0.88
THESL	THC	Facilities	Sq. footage	0.06	0.06	0.24
THESL	THC	ITS & Management	By employee and by type of equipment	0.03	0.03	0.08

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					
THESL	14 Co.	Treasury	% of work performed, FTEs	0.01	0.01	0.10
THESL	Unregulated THESL	Procurement	No. of purchase orders	0.01	0.01	0.39
THESL	Unregulated THESL	Consolidated Billing	% of work performed	0.00	0.00	1.00
THESL	Unregulated THESL	Finance	Audit fees split, no. of invoices, headcount, % of work performed, directly attributable costs	0.47	0.47	3.20
THESL	Unregulated THESL	Organization Effectiveness	Headcount, % of work performed	0.00	0.00	0.04
THESL	Unregulated THESL	Legal	Driver billable hours	0.01	0.01	0.18
THESL	Unregulated THESL	ITS & Management	By employee and by type of equipment	0.12	0.12	0.38

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INTERROGATORY 38:

Reference(s): C1/T3/S1/p.1

It is stated that:

"THC and THESL have completed this consolidation with the result that substantially all of the remaining personnel and associated costs involved in shared services from THC to THESL have been transferred to THESL."

a) Please state whether given the completion of this reorganization, any consideration has been given to merging THC and THESL. If yes, please discuss, if not why not.
b) Please discuss whether or not any cost savings would result from a merger of THESL and THC.

RESPONSE:

a) Consideration was given to merging THC and THESL. However, due to the fact that the Corporation currently holds unregulated subsidiaries and expects to continue to do so going forward, this approach was not pursued.

b) Management does not believe any cost savings would result from a merger of THESL and THC. In fact, such a merger could increase costs by requiring additional effort to track and allocate the costs of unregulated activities in THESL.

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INTERROGATORY 39:

Reference(s): C1/T3/S1/p.2

It is stated that:

"Consequently, services purchased by THESL from THC will be $1.97 million in 2011, comprised of $1.18 million for strategic leadership, stewardship and governance, and $0.79 million for overall finance leadership to the organization. These services will be performed by the Board of Directors, offices of the Chief Executive Office and the Chief Financial Officer."

Please identify the headcount underlying both of these costs.

RESPONSE:

The headcount underlying both of these costs consists of a total of four headcounts, comprised of two headcounts within in each of the offices of the Chief Executive Officer and the Chief Financial Officer.

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INTERROGATORY 40:

Reference(s): C1/T3/S1/App. B/p.3

The table on this page outlines shared services sold by THESL to affiliates for the 2011 Test year.

a) Please state the meaning of the column "Sold to 14 Co."

b) Please provide supporting calculations for the Finance services sold to TH Energy in the amount of $0.48 million and to Unregulated THESL in the amount of $0.47 million.

RESPONSE:

a) 1455948 Ontario Inc. ("14 Co") is a wholly-owned subsidiary of Toronto Hydro Corporation ("THC") and an affiliate of Toronto Hydro-Electric System Limited. Services were sold to 14 Co similarly as they were to THC and Toronto Hydro Energy Services Inc. ("TH Energy").

b) Supporting calculation for the Finance services sold to TH Energy in the amount of $0.48 million can be found in to Exhibit C1, Tab 2, Schedule 3-1: Service Level Agreement, Schedule 3 – Finance.

Supporting calculation for the Finance services sold to Unregulated THESL in the amount of $0.47 million can be found in the table below:

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Payroll	10,660
Accounts Payable	16,058
Reporting Policy	10,909
Financial Planning Admin	1,656
Corporate Tax	39,050
Financial System Support	70,000
Finance – Unregulated	326,128
Total	**474,461**

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INTERROGATORY 41:

Reference(s): B1/T5/S1, Appendix A

This appendix is THC's 2009 Annual Report. On page 1, it is stated that "For the fifth consecutive year, Toronto Hydro Corporation was named one of Canada's Top 100 Employers as chosen by the Canada's Top 100 Employers organization."

The *EDA Weekly* of October 20, 2010 stated that THC had again been selected as one of Canada's Top 100 Employers for 2011 and that more information could be obtained at the web site www.eluta.ca.

The information on this web site rates THC's financial benefits for employees as "above-average" and other benefits as "exceptional."

Please state why it is necessary that THESL, as part of THC, provide "above-average" and "exceptional" benefits and whether or not these ratings would suggest that such benefits could be reduced. If not, please explain why not.

RESPONSE:

In its Canada's Top 100 Employers survey submission, THESL did not state that it offers "above-average" and "exceptional" benefits. The quote from the *EDA Weekly* of October 20, 2010 can be attributed to the editorial perspective that ELUTA has taken in its article. THESL provides a benefits program that is competitive in the markets where it competes for talent. THESL continually reviews its programs and benefits to ensure that they meet the ongoing needs of its employees and support the achievement of superior business results.

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INTERROGATORY 42:

Reference(s): C1/T4/S1, Appendix C, p. 2

Table 5 shows the Benefit Burden Rate for the 2010 Bridge and 2011 Test years. Please provide the 2007 to 2009 actuals for this rate.

RESPONSE:

Table 1: Payroll Burden Rate (%)

	2007 Actuals	2008 Actuals	2009 Actuals	2010 Bridge	2011 Test
Benefit Burden Rate	28.85	28.79	28.58	30.09	32.33

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INTERROGATORY 43:

Reference(s): C2/T1/S2

Please complete the following table:

	2005A vs 2004A	2006A vs 2005A	2007A vs 2006A	2008A vs 2007A	2009A vs 2008A	2010B vs 2009A	2011T vs 2010B
Yearly Market Adjustment/General Increase (%)							
Headcount increase (%)							
Total Compensation Capitalized (%)							

Note: For "Total Compensation Capitalized" please provide the percentage for the year in question, not a year versus year comparison. For the other two columns, please provide the year over year change. A=Actual, B= Bridge, T=Test Year

RESPONSE:

	2005A vs 2004A	2006A vs 2005A	2007A vs 2006A	2008A vs 2007A	2009A vs 2008A	2010B vs 2009A	2011T vs 2010B
Yearly Market Adjustment/General Increase (%)	3%	3.5%	3.25%	3.25%	3%	3%	3%
Headcount increase (%)	7%	3%	11%	1%	2%	11%	9%
Total Compensation Capitalized (%)	46%	50%	44%	46%	46%	47%	52%

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INTERROGATORY 44:

Reference(s): C2/T1/S2/p.2

It is stated that:

"As part of THESL's new five-year Collective Agreement with CUPE effective February 1, 2009, a group incentive program was introduced for unionized employees in the critical front-line roles of Crew Leader and System Response Representative. This new Gain Sharing Program is a groundbreaking achievement, linking pay to successful delivery of specific results."

a) Please state whether the adoption of this program is expected to result in any cost savings to THESL. If yes, please state the amount. If no, please state the additional costs arising from it.
b) Please state whether or not THESL had any studies undertaken or knew of any studies that indicated that Gain Sharing would be a successful innovation for THESL, or had been proven successful elsewhere.

RESPONSE:

a) The Gain Sharing program is a group incentive program based on the achievement of targets and Key Performance Indicators ("KPIs") that are a subset of THESL's scorecard. Since the program's introduction, improvements have occurred in each of the KPIs that are measured under the program: safety, attendance, productivity, and customer reliability. The additional cost arising from the Gain Sharing program for 2009 was $251,521.40; it is estimated to be $263,496 for 2010 and $264,182 for 2011 if participants achieve target for all four KPIs on the Gain Sharing scorecard.

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b) THESL has not undertaken any recent studies related to gain sharing.

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INTERROGATORY 45:

Reference(s): C2/T1/S3/p.1

It is stated that:

"The increase in costs related to the OMERS defined benefit pension plan is due to the increase in FTE between 2009 and 2011 (Based on the reorganization and expected hiring), contributory earnings increasing and a possible increase in contribution rates in 2011."

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. Please state whether or not the applicant's proposed pension costs include this increase. If so, please provide the forecasted increase by years and the documentation to support the increases. If not, please state how the applicant proposes to deal with this increase.

RESPONSE:

THESL's proposed pension costs include the increase announced by OMERS as shown in the table below.

DESCRIPTIONS	2011
Contribution Rate Increase	1%
Contribution Rate up to YMPE	7.4%
Contribution Rate above YMPE	10.7%
Employer's Forecasted Rate Increase Cost	$1.7 M
Employer's Total Forecasted OMERS Costs	$15.5M

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INTERROGATORY 46:

Reference(s): C2/T1/S2/App. A/p.1

Please provide an extended version of Table 1: Employee Compensation including 2007 Actuals and 2008 to 2010 Approved.

RESPONSE:

The Board has not approved any specific compensation at the Business Unit or Corporate level. Please see Appendix A to this Schedule for the historical actuals, bridge and test year.

TABLE 1: EMPLOYEE COMPENSATION

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
Row		2007 Historical Actual	2008 Historical Actual	2009 Historical Actual	2010 Bridge	2011 Test
1	**Number of Employees (FTEs including Part-Time)**					
2	Executive	10	10	9	12	10
3	Managerial	38	41	43	55	53
4	Management/Non-Union	265	275	302	398	479
5	Union *	1,212	1220	1220	1308	1402
6	Total *	1,525	1546	1574	1773	1944
7	** Excludes President & Vice President of CUPE Local One*					
8	**Number of Part-Time Employees**					
9	Executive					
10	Management (Managerial)					
11	Non-Union (Management/Non-Union)					
12	Union					
13	Total					
14	**Total Salary and Wages**					
15	Executive	1,714,398	1,812,507.75	1,782,964.90	2,345,675.00	2,021,671.00
16	Managerial	4,679,679	4,960,742.93	5,670,025.17	7,232,385.00	7,216,041.00
17	Management/Non-Union	23,652,288	24,637,246.30	27,600,854.50	37,044,705.00	45,280,227.00
18	Union	85,537,115	88,723,957.77	91,712,516.73	101,201,545.00	111,347,730.00
19	**Total**	**115,583,480**	**120,134,454.75**	**126,766,361.30**	**147,824,311**	**165,865,669.00**
20	**Total Benefits**					
21	Executive	667,994	818,469.04	787,523.63	1,126,848.00	1,030,425.00
22	Managerial	1,616,795	1,690,280.36	1,918,365.23	2,617,604.00	2,829,923.00
23	Management/Non-Union	8,208,444	8,509,706.95	9,523,017.72	13,668,698.00	17,536,908.00
24	Union	30,339,717	30,960,867.35	31,919,114.86	36,863,855.00	42,773,515.00
25	**Total**	**40,832,950**	**41,979,323.70**	**44,148,021.44**	**54,277,005.00**	**64,170,771.00**
26	**Total Compensation (Salary, Wages, & Benefits)**					
27	Executive	2,382,392	2,630,976.79	2,570,488.53	3,472,523.00	3,052,096.00
28	Managerial	6,296,474	6,651,023.29	7,588,390.40	9,849,989.00	10,045,964.00
29	Management/Non-Union	31,860,731	33,146,953.25	37,123,872.22	50,713,403.00	62,817,135.00
30	Union	115,876,832	119,684,825.12	123,631,631.60	138,065,400.00	154,121,245.00
31	**Total**	**156,416,429**	**162,113,778.45**	**170,914,382.74**	**202,101,316.00**	**230,036,440.00**
32	**Compensation - Average Yearly Base Wages**					
33	Executive	171,440	181,250.78	200,179.08	195,472.92	202,167.10
34	Managerial	122,689	121,783.10	131,760.31	131,101.00	136,151.72
35	Management/Non-Union	89,247	89,665.32	91,326.45	93,197.00	94,589.99
36	Union	70,575	72,699.88	75,168.79	77,379.00	79,402.00
37	**Compensation - Average Yearly Overtime**					
38	Executive	-	-		-	-
39	Managerial	-	-		-	-
40	Management/Non-Union	4,841	4,297.00	9,639.03	3,039.95	2,504.49
41	Union	12,534	9,498.32	13,121.30	10,216.00	11,083.63
42	**Compensation - Average Yearly Incentive Pay**					
43	Executive	59,643	70,902.05	85,714.49	66,473.75	68,100.30
44	Managerial	18,344	22,731.66	23,820.13	22,754.00	24,643.45
45	Management/Non-Union	5,114	6,768.76	6,729.04	7,962.00	8,250.46
46	Union**	4,890	5,063.07	5,805.52	3,422.00	4,120.00
47	***Only includes The Society of Energy Professional, Crew Leaders, System Response Rep*				*(161 FTEs for Union)*	*(187.5 FTEs for union)*
48	**Compensation - Average Yearly Benefits**					
49	Executive	66,799	81,846.90	88,417.76	93,904.00	103,042.50
50	Managerial	42,388	41,495.31	44,579.06	47,449.00	53,394.77
51	Management/Non-Union	30,973	30,970.41	31,510.02	34,388.00	36,637.00
52	Union	25,033	25,369.15	26,161.33	28,186.00	30,502.40
53	**All Inclusive (Base Wages, Overtime, Incentive Pay, Benefits)**					
54	**Total Compensation**	175,664,371	178,510,702.07	193,838,536.83	222,435,763.00	253,482,831.00
55	**Total Compensation Charged to OM&A**	98,090,985	96,609,991.96	105,060,486.96	118,825,184.59	121,925,241.71
56	**Total Compensation Capitalized**	77,573,386	81,900,710.11	88,778,049.87	103,610,578.41	131,557,589.29

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INTERROGATORY 47:

Reference(s): C2/T1/S2/App. A/p.1

At Line 31 of Table 1, which provides a breakdown of employee compensation, a number is provided for "Total Compensation (Salary, Wages & Benefits)" which for the 2010 Test Year is $230,036,440.

At Line 54 of the same Table, a number is provided for "Total Compensation" which for the 2010 Test Year is $253,482,831.

Please state the reason for the difference in these two numbers.

RESPONSE:

Line 31 of Table 1 is comprised of salary, wages, and benefits costs.

Line 54 of Table 1 is comprised of salary, wages, benefits, overtime, and incentive pay costs. The difference is the inclusion of Overtime and Incentive Pay on Line 55.

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INTERROGATORY 48:

Reference(s): C2/T1/S2/App. A/p.1

"Total Compensation" at line 54 of Table 1 is shown as $253,482,831 for the 2011 Test year and $222,435,763 for the 2010 Bridge year. Please provide a breakdown of the $31 million increase between the yearly market adjustment/general increases and the expected increase in headcount.

RESPONSE:

The increase between 2010 Bridge year and 2011 Test year is related to the new hires planned, base salary increases and related benefit costs.

Breakdown of the $31 million

Descriptions	$ (million)
New Hire	$21.9
General Increases and Related Benefit Costs	$9.0
TOTAL	$31.0

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INTERROGATORY 49:

Reference(s): **C2/T1/S3/p.2**

Table 2 provides "Post-Retirement Benefits Costs" for 2009 Actual, 2010 Bridge and 2011 Test years. Please provide an equivalent table incorporating 2007 and 2008 actuals and 2008 to 2010 approved.

RESPONSE:

Table 2: Post-Retirement Benefit Costs ($ millions)

Post Retirement Benefits	2007 Actuals	2008 Actuals
Post Retirement Cost	13.4	13.2
Less; Amount Capitalized	5.6	6.1
Amount Expensed in Each Year	**7.8**	**7.1**

There are no Board-Approved numbers for 2008 to 2010.

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INTERROGATORY 50:

Reference(s): C1/T1/S4/p.6

Page 6 of the *Compensation Program Guide* contains 2010 weightings for various positions in THC.

a) Please provide definitions of the columns "Individual Performance" and "Corporate Performance."

b) Please identify the changes that have been made in these weightings for 2010 as compared to those that were filed last year, e.g. the elimination of the "Affiliate Performance" criteria and the consolidation in the "Position" category as well as any others and state why they were made as well as their expected impact on compensation. Please also discuss how THC's reorganization has impacted these weightings.

RESPONSE:

a) Corporate Performance is determined by THC's ability to achieve its goals outlined in the Company's balanced scorecard. The goals/Key Performance Indicators ("KPIs") and targets are reviewed and approved by THC's Board of Directors annually. The Company's performance in relation to the KPI targets determines the corporate performance result.

Individual Performance is based on an individual's ability to achieve their annual goals. An individual's performance goals are determined based on a cascade of corporate and operational goals related to the individual's strategic and operational emphasis. The goals relate to their respective responsibilities and portfolios, employee engagement and communications, customer service and stakeholder

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relations. Individual objectives are reviewed and approved by their leader annually and are monitored throughout the year.

b) As a result of the reorganization into two primary companies – THC and THESL, performance pay weightings were adjusted to align with the new structure. With the absence of additional affiliate organizations, the "Affiliate Performance" performance pay weighting category and corresponding position levels were removed. Positions that had Affiliate performance weighting were consolidated with the Corporate performance weighting. This weighting adjustment will not change the compensation potential for the incumbents impacted.

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INTERROGATORY 51:

Reference(s): C2/T1/S5/p.3

Table 1 on this page provides "Forecast Retirements" for the 2010 to 2019 period totaling 754 employees.

The equivalent table in THESL's EB-2009-0139 application, contained in Exhibit C2/Tab 1/Schedule 5/page 3 provides "Forecast Retirements" for the 2009 to 2018 period totaling 694 employees.

a) Please provide a breakdown by year for the 2009 to 2019 period which would show increases and decreases by year to explain the additional 60 retirements in this year's application versus last year's application.
b) For the years 2008 to 2010, please provide the number of retirements on which the Board approved rates were set and the actual number of retirements which occurred. For the 2010 actual, please provide the actual to date, plus the forecast for the remainder of the year.

RESPONSE:

a) The first Table below shows THESL's current projection of retirements over the 2010 through 2019 period, while the Table immediately following the one below contains the projected retirements projected as part of THESL's 2010 distribution rates application.

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL
Number of retirements	64[1]	37	50	55	79	68	97	103	89	112	754

[1] Includes projected retirements from 2009 which did not occur and have been rolled forward.

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Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	TOTAL
Number of retirements	53	38	40	56	68	86	67	93	104	89	694

The additional 60 retirements are primarily due to shifting the projection by one year as well as projected retirements that did not occur and have been rolled forward.

b)

	2008	2009	2010**	2010
Actual Retirements	16	30	53	55
Projected Retirements in EB-2007-0680; C2, T1, S6, p. 2	18	34	46	

**To date

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INTERROGATORY 52:

Reference(s): C2/T1/S5/p.3

It is stated that:

"In 2011, THESL continues to upgrade its distribution system infrastructure. In terms of the labour necessary for plan implementation, THESL projects a shortfall based on current staffing levels of approximately 320 full-time employees ("FTEs") in 2011."

In Exhibit C2 Tab 1 Schedule 2 Appendix A, THESL states that total FTEs for the 2011 Test year are 1,944.

Please state whether the statement quoted above would imply that THESL believes that the necessary FTE level in 2011 to upgrade its distribution system infrastructure would be the 1,944 FTEs presently on the payroll, plus an additional 320 employees. If yes, please explain how this number was determined. If no, please clarify what is meant by this statement. Please include a statement as to what THESL believes the ongoing sustainable level of FTEs necessary to complete the ten-year plan would be.

RESPONSE:

The 320 FTEs are not additional full-time employees, but rather represent a capacity gap between current staffing levels and what is needed to:

- Deliver the expanded distribution system infrastructure upgrade program, and,
- Mentor new staff brought in to replace experienced employees nearing retirement.

This 320 FTE gap will be filled through a multi-pronged approach involving:

- New staff hires

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- Harmonization of specialized trades into multi-functional trades
- Use of planned overtime where appropriate
- Deployment of external contractors where appropriate

For each future year within the ten-year plan, staffing requirements will be evaluated based on the specific needs of the distribution system and actual attrition that occurs within the organization.

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INTERROGATORY 53:

Reference(s): C2/T1/S5/p.5

It is stated that:

"THESL secured external resources to support the delivery of the 2010 Capital Program by entering into term contracts with Power Line Plus, Entera and AECON on January 1, 2010. The Design-Build firms provide civil and electrical design, construction and material acquisition services by leveraging the resources of a combined 13 Engineering and construction firms. This component of the staffing strategy will continue to be utilized in 2011."

a) Please state the value of each of these contracts and their term.
b) Please describe the process by which these firms were selected.
c) Please state how many contracts are anticipated to be entered into in 2011, their value and term. Please also provide an update on the status of the 2011 process. If the winning proposals have been determined, please state who the winners are, what they will each be doing and the amount of the winning bid.

RESPONSE:

a) The expected value of the unit price contract, across all contract firms, is approximately $130 Million per year. There is no guaranteed minimum or maximum amount of work to any/all contractors. The contract is structured as a two-year contract with three one-year options for extension if THESL decides to entertain these options. THESL has sole discretion to exercise the options.

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b) THESL went out for competitive bids (via RFP) as per our procurement policy. The contractors were chosen based on predetermined evaluation criteria.

c) In 2011, THESL is continuing to work under the terms of the contract outlined above. Also in 2011 we will need to evaluate whether to exercise the options for year 3, as well as whether to consider additional contractor firms.

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INTERROGATORY 54:

Reference(s): C2/T1/S5/pp.8-9

On page 8, THESL's Trades School program is discussed and it is stated that:

"Between 2003 and 2009, 127 Trades apprentices entered the THESL program. Twenty percent of these apprentices have graduated to date and remain with THESL. Over 89 percent of apprentices have continued in the program."

On page 9, it is stated that there is a 4.5 year lead time required for these apprentices to become fully competent.

With respect to the above:

a) For each of the years 2003 to 2009, please provide the number of apprentices entering the program, the year of graduation, or if they have not graduated, their status today.
b) Please provide the annual costs of the apprentice training program, other than salary and related benefits.
c) For the 11% of apprentices who have not remained in the program, please state the reasons why this has been the case.
d) Please discuss whether the 11% attrition rate is considered normal, below normal or above normal for such a program and also how it compares to THESL's expectations when it commenced the program.

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RESPONSE:

a)

Year	Number Entering Program	Year of Graduation	Status
2003	16	1 - 2006 3 - 2007 11 - 2008	
2004	12	1 - 2007 8 - 2008	
2005	1	1 - 2008	
2006	18	14 – 2010	Currently being placed; under review for graduation in 2010.
2007	37	17 - 2011 16 - 2012	17 - Entering Level 4; 16 – Entering Level 3
2008	29	27 - 2013	In Level 2/3
2009	13	12 - 2014	Completing Level 1/2

b) Annual costs vary by apprentice training level. Over a 4.5-year period apprentice costs total approximately $225K per apprentice. Entry level training is $19K per apprentice.

c) From 2003 to 2009, the 11% who did not remain in the apprenticeship program left Toronto Hydro for a variety of reasons such as: to work for other utilities or utility contractors, personal circumstances, location. In three cases, the decision was made to terminate employment.

d) THESL believes that an 11% attrition rate for such a program is considered normal.

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INTERROGATORY 55:

Reference(s): D1/T12/S1/p.1

Please state whether there have been any changes in THESL's depreciation policies since the filing of its 2010 cost of service application. If there have been any, please state what they are and confirm whether or not there is an impact on the present application.

RESPONSE:

There have not been any changes in THESL's depreciation policies since the filing of its 2010 cost of service application.

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INTERROGATORY 56:

Reference(s): H1/T1/S1/p.7

Table 2, “Summary of Property Taxes by Year” provides a breakdown of property taxes for 2009 Historical, 2010 Bridge and 2011 Test years.

Please expand this table to include 2007 and 2008 actuals and 2008-2010 Board Approved.

RESPONSE:

The table below includes the actual figures for 2007 and 2008. The Board did not approve specific property tax amounts for 2008-2010. As the Board stated with reference to the 2008-2009 amounts: “In other words, the Board does not approve or disapprove any specific line item within the Company’s claim.” (from Decision with Reasons on EB-2007-0680, page 38). For 2010, the Board-approved an overall settlement.

Summary of Property Taxes by Year ($ millions)

	2007 Historical	2008 Historical	2009 Historical	2010 Bridge	2011 Test
Municipal and PILs Property Taxes	6.8	6.9	6.5	6.7	6.8
Property Tax Reassessments(1)	(0.6)	(0.9)	(0.1)	-	-
Total Property Taxes	6.2	6.0	6.4	6.7	6.8

Note (1): The 2009 actual has been updated to include $0.1 of property tax reassessments. The total property tax reported for 2009 has not changed.

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INTERROGATORY 57:

Reference(s): H1/T1/S1/p.6

Table 1 provides a summary of PILs by year for the 2005 to 2011 period. This shows that total PILs drops from $62.7 million in 2005 to $28.1 million in the 2011 Test year. Please state whether this drop can be largely attributed to reductions in tax rates, or if there are any other significant factors contributing to it. If so, please state what any other such factors would be.

RESPONSE:

The decrease in PILS illustrated in Table 1, is primarily from the decrease in income tax rates and from the removal of regulatory assets in the calculation of regulatory taxable income for 2009 and subsequent years.

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INTERROGATORY 58:

Reference(s): P1/T2/S1/p.4

On this page, THESL provides a response to question #7, which is "Has the applicant deducted regulatory assets for tax purposes in 2008 and/or in prior years? *If yes, please explain your reasons in the manager's summary.*" Staff notes that THESL responds "Yes" to this question but does not appear to have provided an explanation.

The Board, in a number of EDR 2008 decisions denied increasing regulatory taxable income through the addition of movements, or recoveries, in regulatory assets, e.g. Brantford Power, PUC. In the Brantford Power Decision (EB-2007-0698) the Board stated that "The appropriate forum for the issues raised by the Company is the Board's pending proceeding on account 1562. Until that proceeding is concluded, there is no basis for the Board to deviate from the findings it has made in other cases where the same issue has been identified."

Please provide an explanation as to why THESL has deducted regulatory assets for tax purposes in 2008 and/or prior years and state whether such a deduction is incorporated into the 2011 PILS calculation. If it is, please provide a justification in light of the Board's findings referenced above and please also provide revised PILs calculations excluding any such amounts.

RESPONSE:

In 2008 and prior years, THESL adjusted its taxable income for regulatory assets for purposes of calculating regulatory taxable income. By calculating taxable income in this manner, the regulatory taxable income more closely resembles actual taxable income and

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actual taxes paid. Since 2008, THESL has followed the decision in Brantford Power and the Board proceedings on account 1562. For the 2011 PILs calculation, THESL has not adjusted the its regulatory taxable income for regulatory assets consistent with the Brantford Power decision and the Board's direction.

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INTERROGATORY 59:

Reference(s): D1/T1/S1

Please provide a Fixed Asset Continuity Schedule as shown in Appendix 2-B of the Filing Requirements.

RESPONSE:

The Fixed Assets Continuity Schedules for the years 2009 (Historical), 2010 (Bridge) and 2011 (Test) are presented in the requested format in Appendix A of this schedule.

Fixed Asset Continuity Schedule

Table 1: Actuals 2009				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.2	-	(0.0)	2.1	-	-	-	-	2.1
CEC	1806	Land Rights	2.0%	1.7	0.0	(1.7)	-	0.2	-	(0.2)	-	-
47	1808	Buildings	2.0%	43.9	0.0	(0.1)	43.8	15.8	0.8	(0.1)	16.6	27.2
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	-	-	11.9	3.8	0.3	-	4.1	7.8
47	1820	Substation Equipment	3.3%	181.5	15.6	4.8	201.8	77.6	5.3	0.7	83.6	118.2
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	326.5	10.5	-	337.0	145.9	12.4	-	158.3	178.7
47	1835	OH Conductors & Devices	4.0%	341.4	11.3	(2.2)	350.5	215.5	12.0	(0.1)	227.4	123.1
47	1840	UG Conduit	4.0%	1,047.3	53.8	-	1,101.1	508.8	38.7	-	547.5	553.7
47	1845	UG Conductors & Devices	4.0%	641.5	39.1	-	680.6	326.7	24.7	-	351.4	329.1
47	1850	Line Transformers	4.0%	608.0	31.0	-	639.0	311.2	22.3	-	333.5	305.5
47	1855	Services (OH & UG)	4.0%	52.5	14.2	2.2	68.9	6.9	3.2	0.1	10.2	58.7
47	1860	Meters	4.0%	137.7	0.1	(4.8)	133.0	89.5	4.5	(0.7)	93.3	39.8
47	1861	Smart Meters	6.7%	60.2	20.3	(20.3)	60.2	8.0	4.0	-	12.0	48.2
47	1861	Suite Meters	6.7%	1.4	1.4	-	2.7	0.1	0.1	-	0.2	2.5
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	-	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	0.0	(0.0)	-	-	-
47	1908	Buildings & Fixtures	2.0%	101.6	0.8	-	102.3	34.7	2.2	-	36.9	65.4
13	1910	Leasehold Improvements	20.0%	18.7	0.3	-	19.0	6.1	3.3	-	9.4	9.7
8	1915	Office Furniture & Equipment 10yr	10.0%	24.0	1.0	(13.8)	11.1	18.9	0.9	(13.8)	6.0	5.1
8	1915	Office Furniture & Equipment 5yr	10.0%					-	-	-	-	-
10	1920	Computer - Hardware	25.0%	48.9	0.1	(15.9)	33.1	39.8	3.2	(15.6)	27.4	5.8
45	1921	Computer - Hardware post Mar 22/04	25.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	25.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	143.3	14.1	(12.3)	145.1	103.8	14.8	(5.5)	113.2	31.9
10	1930	Transportation Equipment - Automobiles	25.0%	1.1	0.2	(0.0)	1.3	1.2	0.4	(0.2)	1.4	(0.1)
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	9.3	1.6	(0.8)	10.2	6.9	0.6	(0.3)	7.2	3.0
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	45.3	10.8	(2.9)	53.2	31.9	3.6	(3.4)	32.2	21.1
10	1930	Transportation Equipment - Work and Service	12.5%	2.5	-	-	2.5	1.7	0.1	-	1.9	0.6
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	31.3	1.2	-	32.5	22.5	1.3	-	23.8	8.6
8	1945	Measurement & Testing Equipment	10.0%	4.5	0.2	-	4.7	4.1	0.1	-	4.2	0.5
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	29.4	0.8	(6.3)	23.9	23.4	1.8	(6.1)	19.0	4.9
8	1960	Miscellaneous Equipment	10.0%	0.1	-	-	0.1	0.1	-	-	0.1	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	14.8	0.3	-	15.2	6.4	1.1	-	7.5	7.7
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.5	0.0	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	51.0	1.6	-	52.5	31.6	2.3	-	33.9	18.7
47	1985	Miscellaneous Fixed Assets	10.0%	0.0	-	-	0.0	0.0	-	-	0.0	-
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(224.2)	(18.5)	-	(242.7)	(34.7)	(8.7)	-	(43.4)	(199.3)
10	2005	Property Under Capital Lease	25.0%	0.9	-	(0.1)	0.8	-	-	-	-	0.8
		Total		3,768.1	211.6	(74.3)	3,905.4	2,014.3	155.5	(45.1)	2,124.6	1,780.8

Note: Components may not add up exactly to Total due to rounding.
Note: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

Table 2: Bridge 2010				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.1	-	(0.0)	2.1	-	-	-	-	2.1
CEC	1806	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1808	Buildings	2.0%	43.8	11.9	(0.0)	55.6	16.6	0.9	(0.0)	17.5	38.2
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	8.1	-	20.0	4.1	0.4	-	4.5	15.5
47	1820	Substation Equipment	3.3%	201.8	2.7	(4.8)	199.7	83.6	5.7	(0.7)	88.6	111.1
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	337.0	24.5	-	361.4	158.3	13.0	-	171.3	190.1
47	1835	OH Conductors & Devices	4.0%	350.5	41.3	-	391.8	227.4	13.7	-	241.1	150.7
47	1840	UG Conduit	4.0%	1,101.1	20.4	-	1,121.6	547.5	40.9	-	588.3	533.2
47	1845	UG Conductors & Devices	4.0%	680.6	70.0	-	750.6	351.4	27.1	-	378.5	372.1
47	1850	Line Transformers	4.0%	639.0	52.7	-	691.7	333.5	23.6	-	357.1	334.6
47	1855	Services (OH & UG)	4.0%	68.9	16.6	-	85.5	10.2	3.1	-	13.3	72.2
47	1860	Meters	4.0%	133.0	4.9	4.8	142.7	93.3	4.6	0.7	98.6	44.1
47	1861	Smart Meters	6.7%	60.2	16.0	(16.0)	60.2	12.0	4.0	-	16.0	44.2
47	1861	Suite Meters	6.7%	2.7	7.6	-	10.3	0.2	0.4	-	0.6	9.7
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	(0.0)	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	2.0%	102.3	13.8	(0.7)	115.5	36.9	2.1	(0.7)	38.3	77.1
13	1910	Leasehold Improvements	20.0%	19.0	0.7	-	19.7	9.4	3.4	-	12.8	6.9
8	1915	Office Furniture & Equipment 10yr	10.0%	11.1	2.1	-	13.2	6.0	0.9	-	6.9	6.3
8	1915	Office Furniture & Equipment 5yr	10.0%					-	-	-	-	-
10	1920	Computer - Hardware	25.0%	33.1	5.2	(0.1)	38.2	27.4	3.3	-	30.7	7.5
45	1921	Computer - Hardware post Mar 22/04	25.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	25.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	145.1	34.5	(1.5)	178.1	113.2	14.3	-	127.4	50.6
10	1930	Transportation Equipment - Automobiles	25.0%	1.3	0.3	(0.2)	1.4	1.4	0.3	(0.2)	1.5	(0.2)
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	10.2	1.9	(0.0)	12.1	7.2	1.2	(0.0)	8.4	3.7
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	53.2	9.5	(2.3)	60.4	32.2	4.3	(2.3)	34.1	26.3
10	1930	Transportation Equipment - Work and Service	12.5%	2.5	-	-	2.5	1.9	0.1	-	2.0	0.5
8	1935	Stores Equipment	10.0%	5.5	0.1	-	5.6	5.5	0.0	-	5.5	0.1
8	1940	Tools, Shop & Garage Equipment	10.0%	32.5	1.9	-	34.3	23.8	1.6	-	25.5	8.9
8	1945	Measurement & Testing Equipment	10.0%	4.7	0.0	-	4.7	4.2	0.1	-	4.3	0.4
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	23.9	2.3	-	26.1	19.0	2.0	-	21.0	5.2
8	1960	Miscellaneous Equipment	10.0%	0.1	-	(0.1)	-	0.1	-	(0.1)	-	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	15.2	-	-	15.2	7.5	1.1	-	8.6	6.6
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.6	-	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	52.5	1.0	-	53.6	33.9	2.3	-	36.2	17.4
47	1985	Miscellaneous Fixed Assets	10.0%	0.0	-	(0.0)	-	0.0	-	(0.0)	-	-
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(242.7)	(28.7)	-	(271.5)	(43.4)	(10.3)	-	(53.6)	(217.8)
10	2005	Property Under Capital Lease	25%	0.8	-	-	0.8	-	-	-	-	0.8
		Total		3,905.4	321.3	(21.1)	4,205.6	2,124.6	164.5	(3.4)	2,285.7	1,919.9

Note: Components may not add up exactly to Total due to rounding.
Note: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

Table 3: Test 2011

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.1	-	-	2.1	-	-	-	-	2.1
CEC	1806	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1808	Buildings	2.0%	55.6	10.9	-	66.6	17.5	1.2	-	18.7	47.9
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	20.0	23.6	-	43.6	4.5	0.9	-	5.4	38.2
47	1820	Substation Equipment	3.3%	199.7	13.6	-	213.4	88.6	6.0	-	94.7	118.7
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	361.4	24.9	-	386.4	171.3	14.0	-	185.4	201.0
47	1835	OH Conductors & Devices	4.0%	391.8	23.5	-	415.3	241.1	14.9	-	256.0	159.3
47	1840	UG Conduit	4.0%	1,121.6	69.0	-	1,190.6	588.3	41.9	-	630.2	560.3
47	1845	UG Conductors & Devices	4.0%	750.6	102.1	-	852.7	378.5	30.3	-	408.8	443.8
47	1850	Line Transformers	4.0%	691.7	36.4	-	728.1	357.1	24.3	-	381.4	346.7
47	1855	Services (OH & UG)	4.0%	85.5	10.4	-	96.0	13.3	3.7	-	17.0	79.0
47	1860	Meters	4.0%	142.7	10.4	-	153.1	98.6	4.8	-	103.4	49.7
47	1861	Smart Meters	6.7%	60.2	9.5	-	69.6	16.0	4.3	-	20.3	49.3
47	1861	Suite Meters	6.7%	10.3	5.2	-	15.5	0.6	0.9	-	1.5	14.0
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	-	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	2.0%	115.5	7.4	-	122.8	38.3	2.3	-	40.6	82.2
13	1910	Leasehold Improvements	20.0%	19.7	0.6	-	20.4	12.8	3.5	-	16.3	4.0
8	1915	Office Furniture & Equipment 10yr	10.0%	13.2	1.6	-	14.9	6.9	1.0	-	7.9	6.9
8	1915	Office Furniture & Equipment 5yr	10.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	25.0%	38.2	9.4	-	47.7	30.7	4.1	-	34.8	12.9
45	1921	Computer - Hardware post Mar 22/04	25.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	25.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	178.1	33.6	-	211.7	127.4	19.2	-	146.7	65.0
10	1930	Transportation Equipment - Automobiles	25.0%	1.4	0.5	-	1.8	1.5	0.4	-	1.9	(0.1)
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	12.1	1.1	-	13.2	8.4	1.4	-	9.8	3.4
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	60.4	12.6	-	73.0	34.1	5.7	-	39.8	33.2
10	1930	Transportation Equipment - Work and Service	12.5%	2.5	-	-	2.5	2.0	0.1	-	2.1	0.4
8	1935	Stores Equipment	10.0%	5.6	0.0	-	5.6	5.5	0.0	-	5.5	0.1
8	1940	Tools, Shop & Garage Equipment	10.0%	34.3	1.9	-	36.3	25.5	1.8	-	27.2	9.0
8	1945	Measurement & Testing Equipment	10.0%	4.7	0.1	-	4.8	4.3	0.1	-	4.4	0.4
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	26.1	0.8	-	26.9	21.0	2.1	-	23.1	3.8
8	1960	Miscellaneous Equipment	10.0%	-	-	-	-	-	-	-	-	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	15.2	-	-	15.2	8.6	1.1	-	9.8	5.4
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.6	-	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	53.6	2.4	-	56.0	36.2	2.2	-	38.4	17.6
47	1985	Miscellaneous Fixed Assets	10.0%	-	-	-	-	-	-	-	-	-
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(271.5)	(14.6)	-	(286.1)	(53.6)	(11.2)	-	(64.9)	(221.3)
10	2005	Property Under Capital Lease	25%	0.8	-	-	0.8	-	-	-	-	0.8
		Total		4,205.6	397.1	-	4,602.8	2,285.7	181.1	-	2,466.8	2,136.0

Less: Fully Allocated Depreciation	
Transportation	(2.8)
Net Depreciation	178.3

Note: Components may not add up exactly to Total due to rounding.
Note: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 60:

Reference(s): B1/ T10/ S1/p.15/ 2009 Annual Information Form

Note (v), Street Lighting Activities, states with reference to the Board's February 11, 2010 Decision regarding the treatment of streetlighting assets that: "Management is currently evaluating the impact of this decision on its regulated and unregulated businesses and whether to transfer the streetlighting assets to LDC."

a) Please provide an update on this evaluation.
b) Please confirm that no streetlighting assets are contained in the 2011 rate base, or if any are, please provide an explanation.

RESPONSE:

a) The project activities are currently in progress. A preliminary summary of the findings is expected in December 2010.

b) No street lighting assets are contained in the 2011 rate base.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 61:

Reference(s): **D1/T7/S1/p.16**
A/T1/S1, p.4
D1/T9/S8

Table 2 of the first reference above contains an item in Emerging Requirements for an "Energy Storage Project" for the year 2011 in the amount of $30 million.

The second reference which is contained in the application overview discusses THESL's plans to install a 4 MW energy storage system at a transformer station in downtown Toronto to provide short duration emergency supply. It is stated that:

> "The costs of this project will be entirely contained within CWIP, and does not in any way impact ratebase or revenue requirement in 2011.
>
> In this Application, THESL seeks Board approval in principle of the project and its categorical eligibility for inclusion in ratebase commencing in 2012. THESL is presenting information on this project in this Application because of the unusual completion horizon of the project, which is longer than one year and atypical of most discrete capital projects undertaken by THESL"

The third reference above provides a more detailed description of the energy storage project.

a) Please confirm that the "Energy Storage Project" shown in the amount of $30 million in Table 2 is the same project that is discussed in the second and third references. If this is not the case, please clarify.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

b) Please state whether any other projects included in Table 2 of the first reference are entirely contained in CWIP. If yes, please specify the projects and amounts.

c) Please state the legal basis on which THESL believes the Board could provide approval in principle of this project, what exactly it would mean and the extent to which THESL believes such approval would bind a Panel reviewing any subsequent application.

d) Please state how many other of THESL's forecast capital projects have completion horizons longer than one year.

e) Please provide a cost/benefit analysis of this project.

f) Please state why this project is being undertaken by the distribution company as compared to an unregulated affiliate.

RESPONSE:

a) Confirmed.

b) Table 2 of the first reference noted above speaks to THESL's capital portfolios. For the Test year such portfolios consist of a multitude of different projects that will be undertaken, with the exception of the Energy Storage Project, and Station System Enhancements, which specifically refer to individual projects. Both of these projects identified will be entirely contained in CWIP during 2011.

c) THESL appreciates that the Board cannot approve the project for inclusion in ratebase and revenue requirement in the 2011 rate year, and does not seek that approval. However, for the reasons described THESL seeks an indication from the Board of its view of the categorical eligibility of this project for inclusion in ratebase, given the long lead times and substantial capital involved. Were this not a frontier

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

project with those characteristics, THESL would not request such an indication from the Board.

Various options are open to the Board. For example, the Board might indicate that there is no categorical barrier to its inclusion in ratebase but that a future panel would have to approve the cost consequences of the project and that its finding this year in no way binds a future panel. Alternately, the Board could indicate that the project as proposed is ineligible for inclusion in ratebase, in which case THESL would act accordingly. In neither case would the Board be exercising specific legal jurisdiction to find a revenue requirement or rates. Nevertheless, an indication from the current panel would be meaningful to THESL and THESL sees the request as a reasonable one in the circumstances.

d) THESL does not specifically maintain information on completion horizons for all projects forecasted. For the most part, the majority of THESL's projects are broken down into smaller phases with a completion horizon of less than one year. Quantifying the magnitude of all projects forecast to have a completion horizon of longer than one year would require further analysis and validation by THESL, which cannot be provided within the given timeline as THESL had not been required to maintain such information.

e) This project has a benefit/cost ratio greater than unity. The aggregate benefits of the 4MW energy storage system are $8,162/kW based on THESL outage cost curves, projected Ontario electricity market prices for on/off-peak energy and associated grid benefits from US Department of Energy (DOE) research completed by Sandia Labs in

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

February, 2010 DOE. The cost of the energy storage is $7,500/kW. The ten-year analysis and references are attached as Appendix A.

COST & BENEFIT ANALYSIS FOR ENERGY STORAGE

ENERGY STORAGE CAPACITY	4000	kW
	24000	kWh
SAIFI	1.6	#
SAIDI	1.38	hours
$SAIFI_{EFFECT}$	$ 30	/Interruption
$SAIDI_{EFFECT}$	$ 15	/Second stage

HOEP	
Off Peak Charging	
$ 0.05 /kWh	
On Peak Discharge	
$ 0.10 /kWh	
Round-trip Efficiency	80%

#	BENEFIT TYPE	BENEFIT ($/kW)	YEAR 1	2	3	4	5	6	7	8	9	10	BASIS	SANDIA LABS Low	Avg.	High
1	Station Outage Avoidance	$ 678	$ 69	$ 76	$ 85	$ 95	$ 107	$ 120	$ 135	$ 153	$ 173	$ 197	Cost Curve			
2	Defer Distribution Upgrade	$ 919											Sandia Labs	759	919	1079
3	On/Off-Peak Cost Mgmt.	$ 328	$ 36	$ 39	$ 43	$ 47	$ 52	$ 58	$ 64	$ 71	$ 79	$ 88	HOEP Market			
4	Area Regulation	$ 1,398											Sandia Labs	785	1397.5	2010
5	Congestion Relief	$ 86											Sandia Labs	31	86	141
6	Supply Reserve Capacity	$ 535											Sandia Labs	359	534.5	710
7	Station Control UPS	$ 2,400											Sandia Labs	1800	2400	3000
8	Voltage Support	$ 400											Sandia Labs		400	
9	Power Quality	$ 669											Sandia Labs	359	668.5	978
10	Renewables Integration (Short Dur.)	$ 750											Sandia Labs	500	750	1000
11	TOTAL	$ 8,162														

#	CAPITAL COST	COST ($/kW)
12	Energy Storage System	$ (7,500)

NOTES:
- a Median NPV values used per 2010 Sandia Labs Study
- b THESL cost curve used for Station Outage Avoidance
- c Hourly Ontario Market Price (HOEP) forecast used for On/Off-Peak Cost Mgmt.
- d Escalation of 2.5% annually
- e NPV calculated using 10 year term, 10% discount rate

REFERENCE: FEB., 2010 DOE REPORT BY SANDIA LABS (SAND2010-0815) <u>"ENERGY STORAGE FOR THE ELECTRICITY GRID: BENEFITS AND MARKET POTENTIAL ASSESSMENT GUIDE"</u>

f) This project is proposed principally as a distribution investment for power quality purposes and to mitigate the impact of loss of supply, and not a generation asset. From a distribution system perspective, this project provides similar distribution functionality as voltage regulators which have been used as distribution assets for decades with the added benefits of emergency backup supply, and interconnection points for additional mobile standby emergency generation. There are additional benefits associated with the energy storage capacity of this battery system that can be realized as smart grid technologies emerge on the distribution system.

Toronto Hydro-Electric System Limited
EB-2010-0142
Exhibit R1
Tab 1
Schedule 61
Appendix A
Filed: 2010 Dec 6
(232 pages)

SANDIA REPORT

SAND2010-0815
Unlimited Release
Printed February 2010

Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide

A Study for the DOE Energy Storage Systems Program

Jim Eyer

Garth Corey

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Sandia National Laboratories

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Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide

A Study for the DOE Energy Storage Systems Program

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Contract #10612

Abstract

This guide describes a high-level, technology-neutral framework for assessing potential benefits from and economic market potential for energy storage used for electric-utility-related applications. The overarching theme addressed is the concept of combining applications/benefits into attractive value propositions that include use of energy storage, possibly including distributed and/or modular systems. Other topics addressed include: high-level estimates of application-specific lifecycle benefit (10 years) in $/kW and maximum market potential (10 years) in MW. Combined, these criteria indicate the economic potential (in $Millions) for a given energy storage application/benefit.

The benefits and value propositions characterized provide an important indication of storage system cost targets for system and subsystem developers, vendors, and prospective users. Maximum market potential estimates provide developers, vendors, and energy policymakers with an indication of the upper bound of the potential demand for storage. The combination of the value of an individual benefit (in $/kW) and the corresponding maximum market potential estimate (in MW) indicates the possible impact that storage could have on the U.S. economy.

The intended audience for this document includes persons or organizations needing a framework for making first-cut or high-level estimates of benefits for a specific storage project and/or those seeking a high-level estimate of viable price points and/or maximum market potential for their products. Thus, the intended audience includes: electric utility planners, electricity end users, non-utility electric energy and electric services providers, electric utility regulators and policymakers, intermittent renewables advocates and developers, Smart Grid advocates and developers, storage technology and project developers, and energy storage advocates.

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Introduction

Electric energy storage is poised to become an important element of the electricity infrastructure of the future. The storage opportunity is multifaceted – involving numerous stakeholders and interests – and could involve potentially rich value propositions. Those rich value propositions are possible because, as described in this report, there are numerous potentially complementary and significant benefits associated with storage use that could be aggregated into attractive value propositions. In addition, proven storage technologies are in use today, while emerging storage technologies are expected to have improved performance and/or lower cost. In fact, recent improvements in energy storage and power electronics technologies, coupled with changes in the electricity marketplace, indicate an era of expanding opportunity for electricity storage as a cost-effective electric energy resource.

Scope and Purpose

This guide provides readers with a high-level understanding of important bases for electric-utility-related business opportunities involving electric energy storage. More specifically, this guide is intended to give readers a basic understanding of the benefits for electric-utility-related uses of energy storage.

The guide includes characterization of 26 benefits associated with the use of electricity storage for electric-utility-related applications. The 26 storage benefits characterized are categorized as follows: 1) Electric Supply, 2) Ancillary Services, 3) Grid System, 4) End User/Utility Customer, 5) Renewables Integration, and 6) Incidental. For most of these benefits, the financial value and maximum market potential are estimated. An estimate of the potential economic impact associated with each benefit is also provided.

As a complement to characterizations of individual benefits, another key topic addressed is the concept of aggregating benefits to comprise financially attractive value propositions. Value propositions examples are provided.

Also addressed are storage opportunity drivers, challenges, and notable developments affecting storage. Finally, observations and recommendations are provided regarding the needs and opportunities for electric-energy-storage-related research and development.

Intended Audience

The intended audience for this guide includes persons or organizations needing a framework for making first-cut or high-level estimates of benefits for a specific storage project and/or those seeking a high-level estimate of viable price points and/or maximum market potential for their products. Thus, the intended audience includes, in no particular order: electric utility planners and researchers, non-utility electricity service providers and load aggregators, electricity end users, electric utility regulators and policymakers, and storage project and technology developers and vendors.

Value Propositions

As a complement to coverage of *individual* benefits, a key topic addressed in this guide is the *aggregation* of benefits into financially attractive *value propositions*. That is important because, in many cases, the value of a *single* benefit may not exceed storage cost whereas the value of *combined* benefits may be greater than the cost.

Characterizing the full spectrum of possible value propositions is beyond the scope of this guide; however, eight potentially attractive value propositions are characterized as examples:

1. Electric Energy Time-shift Plus Transmission and Distribution Upgrade Deferral
2. Time-of-use Energy Cost Management Plus Demand Charge Management
3. Renewables Energy Time-shift Plus Electric Energy Time-shift
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Notable Challenges for Storage

Clearly, there are important challenges to be addressed before the full potential for storage is realized. At the highest level, in most cases storage cost exceeds *internalizable* benefits[*] for a variety of reasons, primarily the following:

- High storage cost (relative to internalizable benefits) for modular storage.
- To a large extent, pricing of electric energy and services does not enable storage owners to internalize most benefits.
- Limited regulatory 'permission' to use storage and/or to share benefits among stakeholders – especially benefits from distributed/modular storage.
- Key stakeholders have limited or no familiarity with storage technology and/or benefits.
- Infrastructure needed to control and coordinate storage, especially smaller distributed systems, is limited or does not exist.

[*] The concept of an internalizable benefit is an important theme for this report. An internalizable benefit is one that can be 'captured', 'realized', or received by a given stakeholder. An internalizable *financial* benefit takes the form of revenue and/or a cost reduction or avoided cost.

Notable Storage Opportunity Drivers

Some notable recent and emerging developments driving the opportunities for storage include the following (in no particular order):

- Modular storage technology development in response to the growing market for hybrid vehicles and for portable electronic devices.
- Increasing interest in managing peak demand and reliance on 'demand response' programs – due to peaking generation and transmission constraints.
- Expected increased penetration of distributed energy resources.
- Adoption of the Renewables Portfolio Standard, which will drive increased use of renewables generation with intermittent output.
- Financial risk that limits investment in new transmission capacity, coupled with increasing congestion on some transmission lines and the need for new transmission capacity in many regions.
- Increasing emphasis on richer electric energy and services pricing, such as time-of-use energy prices, locational marginal pricing, and increasing exposure of market-based prices for ancillary services.
- The increasing use of distributed energy resources and the emergence of Smart Grid and distributed energy resource and load aggregation.
- Accelerating storage cost reduction and performance improvement.
- Increasing recognition by lawmakers, regulators, and policymakers of the important role that storage should play in the electricity marketplace of the future.

Research and Development Needs and Opportunities

The following R&D needs and opportunities have been identified as ways to address some of the important challenges that limit increased use of storage:

1. Establish consensus about priorities and actions.
2. Identify and characterize attractive value propositions.
3. Identify and characterize important challenges and possible solutions.
4. Identify and develop standards, models, and tools.
5. Ensure robust integration of distributed/modular storage and Smart Grid.
6. Develop more refined market potential estimates.
7. Develop model risk and reward sharing mechanisms.
8. Develop model rules for utility ownership of distributed/modular storage.
9. Characterize, understand, and communicate the *societal* value proposition for storage.

Key Assumptions and Primary Results

Key assumptions and primary results from the guide are provided in Table ES-1. That table contains five criteria for the 17 primary benefits characterized in this report. Discharge duration indicates the amount of time that the storage must discharge at its rated output before charging. Capacity indicates the range of storage system power ratings that apply for a given benefit. The benefit indicates the present worth of the respective benefit type for 10 years (2.5% inflation, 10% discount rate). Potential indicates the maximum market potential for the respective benefit over 10 years. Economy reflects the total value of the benefit given the maximum market potential.

Table ES-1. Summary of Key Assumptions and Results

#	Benefit Type	Discharge Duration*		Capacity (Power: kW, MW)		Benefit ($/kW)**		Potential (MW, 10 Years)		Economy ($Million)†	
		Low	High	Low	High	Low	High	CA	U.S.	CA	U.S.
1	Electric Energy Time-shift	2	8	1 MW	500 MW	400	700	1,445	18,417	795	10,129
2	Electric Supply Capacity	4	6	1 MW	500 MW	359	710	1,445	18,417	772	9,838
3	Load Following	2	4	1 MW	500 MW	600	1,000	2,889	36,834	2,312	29,467
4	Area Regulation	15 min.	30 min.	1 MW	40 MW	785	2,010	80	1,012	112	1,415
5	Electric Supply Reserve Capacity	1	2	1 MW	500 MW	57	225	636	5,986	90	844
6	Voltage Support	15 min.	1	1 MW	10 MW	400		722	9,209	433	5,525
7	Transmission Support	2 sec.	5 sec.	10 MW	100 MW	192		1,084	13,813	208	2,646
8	Transmission Congestion Relief	3	6	1 MW	100 MW	31	141	2,889	36,834	248	3,168
9.1	T&D Upgrade Deferral 50th percentile††	3	6	250 kW	5 MW	481	687	386	4,986	226	2,912
9.2	T&D Upgrade Deferral 90th percentile††	3	6	250 kW	2 MW	759	1,079	77	997	71	916
10	Substation On-site Power	8	16	1.5 kW	5 kW	1,800	3,000	20	250	47	600
11	Time-of-use Energy Cost Management	4	6	1 kW	1 MW	1,226		5,038	64,228	6,177	78,743
12	Demand Charge Management	5	11	50 kW	10 MW	582		2,519	32,111	1,466	18,695
13	Electric Service Reliability	5 min.	1	0.2 kW	10 MW	359	978	722	9,209	483	6,154
14	Electric Service Power Quality	10 sec.	1 min.	0.2 kW	10 MW	359	978	722	9,209	483	6,154
15	Renewables Energy Time-shift	3	5	1 kW	500 MW	233	389	2,889	36,834	899	11,455
16	Renewables Capacity Firming	2	4	1 kW	500 MW	709	915	2,889	36,834	2,346	29,909
17.1	Wind Generation Grid Integration, Short Duration	10 sec.	15 min.	0.2 kW	500 MW	500	1,000	181	2,302	135	1,727
17.2	Wind Generation Grid Integration, Long Duration	1	6	0.2 kW	500 MW	100	782	1,445	18,417	637	8,122

*Hours unless indicated otherwise. min. = minutes. sec. = seconds.
**Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.
†Based on potential (MW, 10 years) times average of low and high benefit ($/kW).
†† Benefit for *one year*. However, storage could be used at more than one location at different times for similar benefits.

Financial benefits and maximum market potential estimates for the U.S. are provided in Figure ES-1. The same values for California are provided in Figure ES-2.

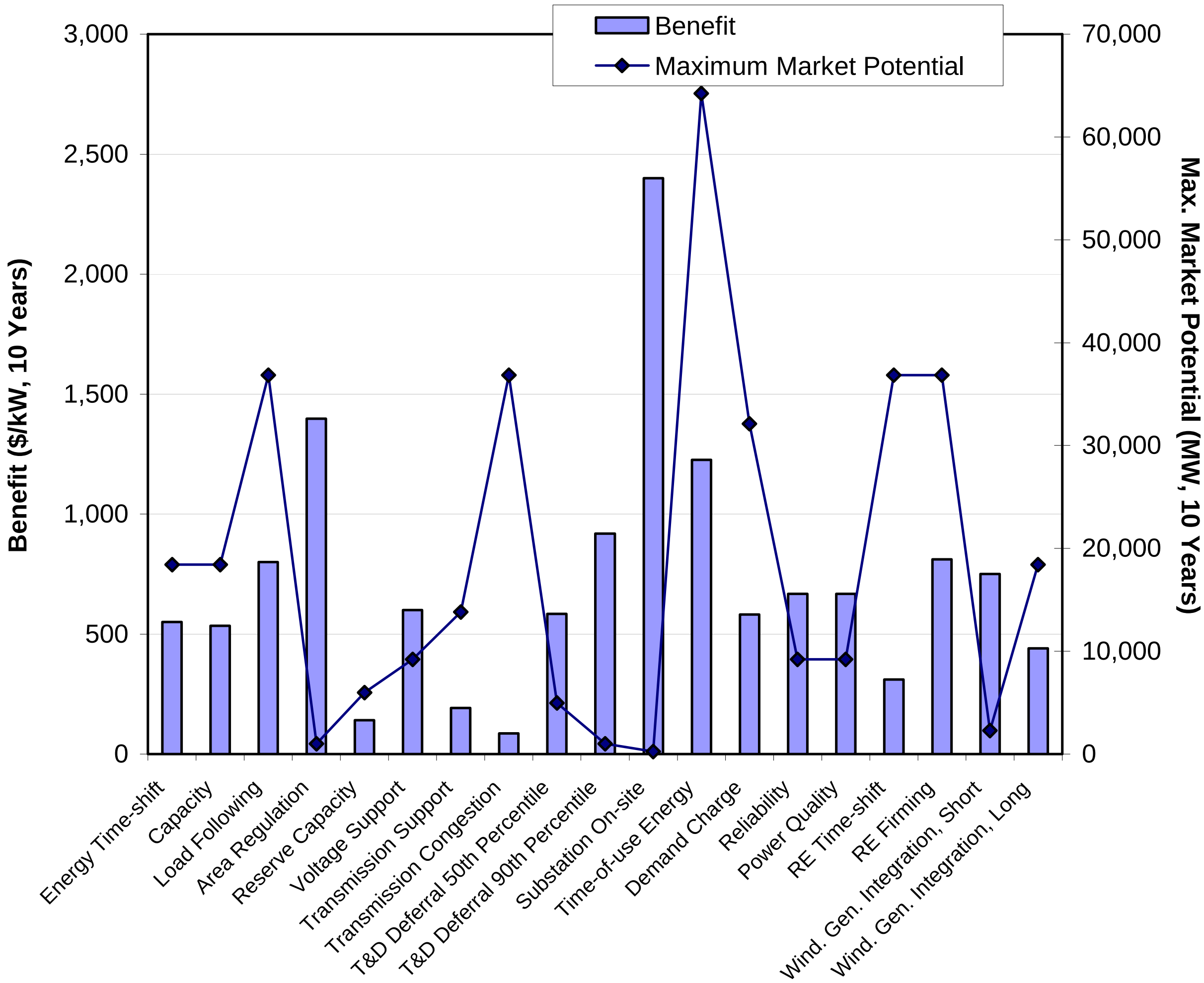

Figure ES-1. Application-specific 10-year benefit and maximum market potential estimates for the U.S.

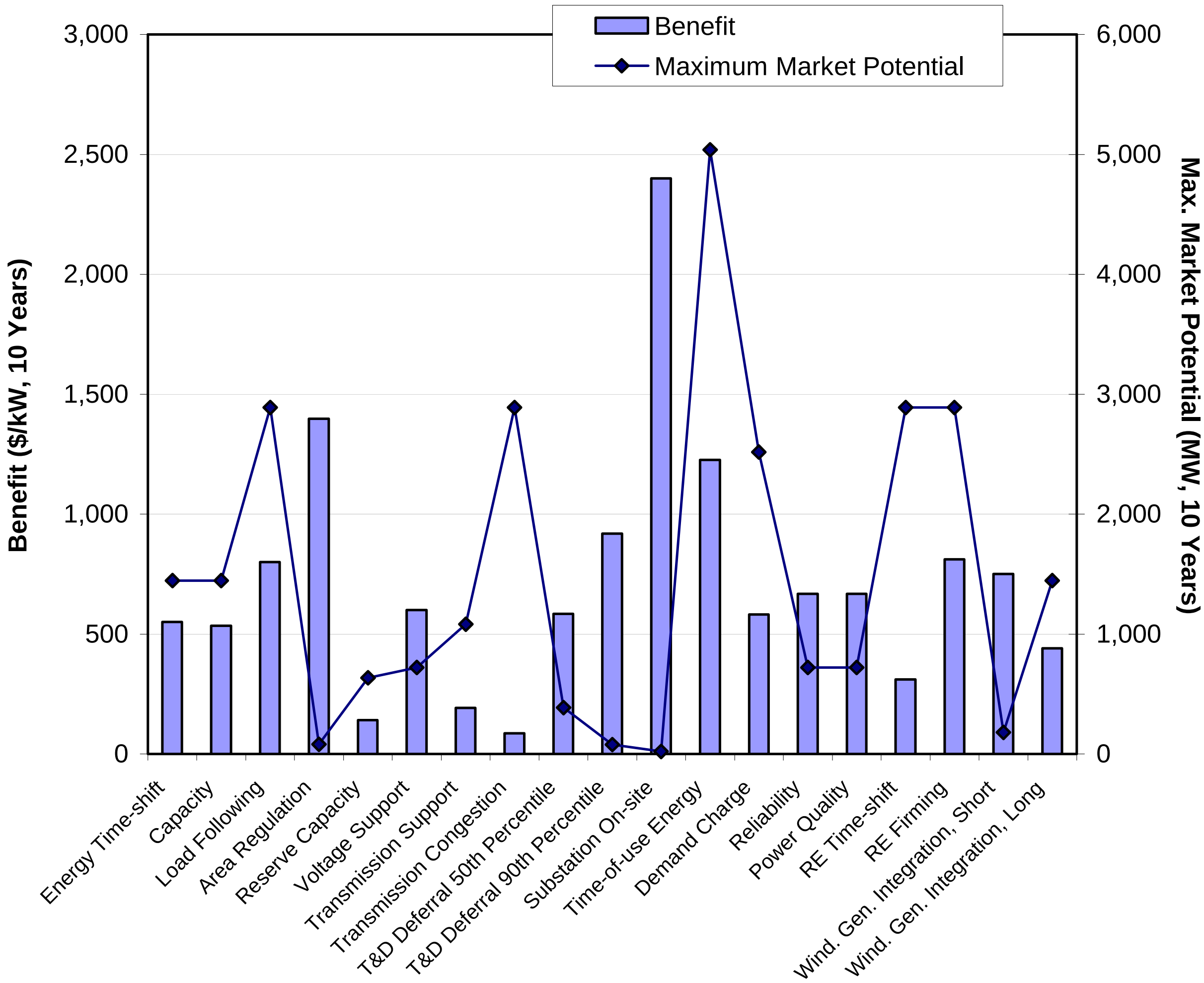

Figure ES-2. Application-specific 10-year benefit and maximum market potential estimates for California.

Care must be used when aggregating specific benefits and market potential values because there may be technical and/or operational conflicts, and/or institutional barriers may hinder or even preclude aggregation, as described in Section 4.4.2.

Acronyms and Abbreviations

AC	alternating current
A/C	air conditioning
ACE	area control error
AGC	automated generation control
AMI	Advanced Metering Infrastructure
CAES	compressed air energy storage
CAISO	California Independent System Operator
CEC	California Energy Commission
C&I	commercial and industrial (energy users)
DC	direct current
DER	distributed energy resource(s)
DOB	dynamic operating benefit
DOE	U.S. Department of Energy
ELCC	effective load carrying capacity
EPRI	Electric Power Research Institute
EV	electric vehicle
FACTS	flexible AC transmission systems
FERC	Federal Energy Regulatory Commission
kW	kilowatt
kWh	kilowatt-hour
kV	kilovolt
kVA	kilovolt-Ampere (or kilovolt-Amp)
kVAR	kilovolt-Ampere reactive (or kilovolt-Amp reactive)
IEEE	Institute of Electronics and Electrical Engineers
IOU	investor-owned utility
ISO	independent system operator
I^2R	pronounced “I squared R” meaning current squared times electric resistance
LDC	load duration curve
Li-ion	lithium-ion
MES	modular energy storage

MW	megawatt
MWh	megawatt-hour
MVA	megavolt-Ampere (or megavolt-Amp)
Na/S	sodium/sulfur
NERC	North American Electric Reliability Council
NiCad	nickel-cadmium
Ni-MH	nickel-metal hydride
O&M	operation and maintenance
ORNL	Oak Ridge National Laboratory
PCU	power conditioning unit
PEAC	Power Electronics Applications Center
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PHEV	plug-in hybrid electric vehicle
PV	photovoltaic
PW	present worth (factor)
R&D	research and development
RPS	Renewables Portfolio Standard
SCADA	supervisory control and data acquisition
SMES	superconducting magnetic energy storage
SNL	Sandia National Laboratories
StatCom	static synchronous compensator
T&D	transmission and distribution
THD	total harmonic distortion
TOU	time-of-use (energy pricing)
UPS	uninterruptible power supply
VAR	volt-Amperes reactive (or volt-Amps reactive)
VOC	variable operating cost
VOS	value-of-service
Zn/Br	zinc/bromine

Glossary

Area Control Error (ACE) – The momentary difference between electric supply and electric demand within a given part of the electric grid (area).

Automated Generation Control (AGC) – A protocol for dispatching electric supply resources (possibly including demand management) in response to changing demand. AGC resources often respond by changing output at a rate of a few percentage points per minute over a predetermined output range. The AGC signal can vary as frequently as every six seconds though generation is rarely called upon to respond that frequently. Typically, generation responds to an average of that more frequent signal, such that a response (change of output) is required once per minute or perhaps as infrequently as every five minutes.

Application – A specific way or ways that energy storage is used to satisfy a specific need; how/for what energy storage is used.

Arbitrage – Simultaneous purchase and sale of identical or equivalent commodities or other instruments across two or more markets in order to benefit from a discrepancy in their price relationship.

Benefit – See Financial Benefit.

Beneficiaries – Entities to whom financial benefits accrue due to use of a storage system.

Carrying Charges – The annual financial requirements needed to service debt and/or equity capital used to purchase and to install capital equipment (*i.e.*, a storage plant), including tax effects. For utilities, this is the revenue requirement. See also Fixed Charge Rate.

Combined Applications – Energy storage used for two or more *compatible* applications.

Combined Benefits – The sum of all benefits that accrue due to use of an energy storage system, regardless of the purpose for installing the system.

Demand Response – Controlled reduction of power draw by electricity end users accomplished via automated communication and control protocols done to balance demand and supply, possibly *in lieu* of adding generation and/or transmission and distribution (T&D) capacity.

Discharge Duration – Total amount of time that the storage plant can discharge, at its nameplate rating, without recharging. Nameplate rating is the nominal full-load rating, not the emergency, short-duration, or contingency rating.

Discount Rate – The interest rate used to discount future cash flows to account for the time value of money. For this document, the assumed value is 10%.

Dispatchable – Electric power resource whose output can be controlled – increased and/or decreased – as needed. Applies to generation, storage, and load-control resources.

Diurnal – Having a daily cycle or occurring every day.

Diversity – The amount of variability and/or difference there is among members of a group. To the extent that electric resources are diverse – with regard to geography and/or fuel – their reliability is enhanced because diversity limits the chance that failure of one or a few individual resources will cause significant problems.

Economic Benefit – The sum of all financial benefits that accrue to all beneficiaries using storage. For example, if the average financial benefit is $100 for 1 million storage users then the *economic* benefit is $100 × 1 million = $100 Million. See Financial Benefit.

Efficiency (**Storage Efficiency**) **–** See Round-trip Efficiency.

Effective Load Carrying Capacity (ELCC) – A characterization of a generator's contribution to planning reserves for a given level of electric supply system reliability. ELCC is a robust and mathematically consistent measure of capacity value. ELCC can be used to establish appropriate payments for resources used to provide capacity needed to meet system reliability goals.

Financial Benefit (Benefit) – Monies received and/or cost avoided by a specific beneficiary, due to use of energy storage.

Financial Life –The plant life assumed when estimating lifecycle costs and benefits. A plant life of 10 years is assumed for lifecycle financial evaluations in this document (*i.e.*, 10 years is the standard assumption value).

Fixed Charge Rate – The rate used to convert capital plant installed cost into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes. The standard assumption value is 0.13 for utilities.

Flexible AC Transmission Systems (**FACTS**) **–** "A power electronic-based system and other static equipment that provide control of one or more alternating current (AC) transmission system parameters to enhance controllability and increase power transfer capability."[*]

I^2R Energy Losses – Energy losses incurred during transmission and distribution of electric energy, due to heating in an electrical system, caused by electrical currents in the conductors of transformer windings or other electrical equipment. I^2R (pronounced I squared R) indicates that those energy losses are a function of the square of the current (I^2) times the resistance (R) per Joule's Law (which characterizes the amount of heat generated when current flows through a conductor). So, for example, reducing current by 50% reduces I^2R energy losses to one quarter of the original value.

Inflation Rate (Inflation) – The annual average rate at which the price of goods and services increases during a specific time period. For this document, inflation is assumed to be 2.5% per year.

Internalizable Benefit – A benefit (revenue and/or reduced cost) that accrues, in part or in whole, to a *specific* stakeholder or stakeholders. A benefit is most readily internalizable if there is a price associated with it.

Lifecycle – See Financial Life.

Lifecycle Benefit – Present worth (value) of financial benefits that are expected to accrue over the life of a storage plant.

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[*] Definition provided by the Institute of Electrical and Electronics Engineers (IEEE).

Load Duration Curve (LDC) – Hourly demand values (usually for one year) arranged in order of magnitude, regardless of which hour during the year that the demand occurs. Values to the left represent the highest levels of demand during the year and values to the right represent the lowest demand values during the year.

Loss of Load Expectation – Measure of the electric supply system's reliability that indicates the adequacy of the system to satisfy demand.

Loss of Load Probability – measure of the electric supply system's reliability indicating the likelihood that the system cannot satisfy demand.

Market Estimate – The estimated amount of *energy storage* capacity (MW) that will be installed. For this document, market estimates are made for a 10-year period. Market estimates reflect consideration of prospects for lower cost alternatives to compete for the same applications and benefits. (The Market Estimate is a portion of the Maximum Market Potential.)

Maximum Market Potential – The maximum potential for *actual sale and installation of energy storage,* estimated based on reasonable assumptions about technology and market readiness and trends, and about the persistence of existing institutional challenges. In the context of this document, it is the *plausible market potential* for a given application. (The Maximum Market Potential is a portion of the Market Technical Potential.)

Market Technical Potential – The estimated *maximum possible* amount of energy storage (MW and MWh) that could be installed over 10 years, *given purely technical constraints*.

Plant Rating (Rating) – Storage plant ratings include two primary criteria: 1) *power* – nominal power output and 2) e*nergy* – the maximum amount of energy that the system can deliver to the load without being recharged.

Present Worth Factor (PW Factor) – A value used to estimate the present worth of a stream of annual expenses or revenues. It is a function of a specific combination of investment duration (equipment life), financial escalation rate (*e.g.*, inflation), and an annual discount rate. The PW factor of 7.17 used in this guide is based on the following standard assumption values: a 10-year equipment life, 2.5% annual price/cost inflation rate, 10% annual discount rate, and a mid-year convention.

Price Inflation Rate (Inflation) – See Inflation.

Revenue Requirement – For a utility, the amount of annual revenue required to pay carrying charges for capital equipment and to cover expenses including fuel and maintenance. See also Carrying Charges and Fixed Charge Rate.

Round-trip Efficiency – The amount of electric energy output from a given storage plant/system per unit of electric energy input.

Smart Grid – A concept involving an electricity grid that delivers electric energy using communications, control, and computer technology for lower cost and with superior reliability. As characterized by the U.S. Department of Energy, the following are characteristics or performance features of a Smart Grid: 1) self-healing from power disturbance events; 2) enabling active participation by consumers in demand response; 3) operating resiliently against physical and cyber attack; 4) providing power quality for 21st century needs; 5) accommodating all generation and storage options; 6) enabling new products, services, and markets; and 7) optimizing assets and operating efficiently.

Societal Benefit – A benefit that accrues, in part or in whole, to utility customers as a group and/or to society at large.

Standard Assumption Values (Standard Values) – Standardized/generic values used for example calculations. For example, financial benefits are calculated based on the following standard assumption values: a 10-year lifecycle, 10% discount rate, and 2.5% annual inflation. See also Standard Calculations.

Standard Calculations – Methodologies for calculating benefits and market potential **–** used in conjunction with Standard Assumption Values.

Storage Discharge Duration – See Discharge Duration.

Storage System Life (System Life) – The period during which the storage system is expected to be operated. For this document, the Storage System Life is equal to the Financial Life.

Supervisory Control and Data Acquisition (SCADA) – A generic term describing various approaches used to automate monitoring and control of T&D equipment and to gather and store data about equipment operation.

1. Introduction

1.1. About This Document

This document provides high-level characterizations of electric energy storage applications, including key characteristics needed for storage used in electric-grid-related applications. Financial benefits and maximum market potential estimates, in California and the U.S., are provided for those applications.

Financial benefit estimates provide an indication of the financial attractiveness of storage for specific applications. Individual benefits provide bases for value propositions that comprise two or more individual benefits, especially value propositions involving benefits that exceed cost.

Application-specific maximum market potential estimates provide an indication of the potential demand for storage. Values for application-specific benefits are multiplied by the maximum market potential to estimate the potential economic effect ($Millions) for storage used for specific applications.

The goal is to provide 1) bases for first-cut or screening-level evaluation of the benefits and market potential for specific, possibly attractive, storage value propositions and 2) a possible framework for making region-specific or circumstance-specific estimates.

The presentation in this document is storage-technology-neutral, though there is some coverage of storage technology system characteristics as context for coverage of applications, benefits, and value propositions. In fact, value propositions characterized using values and insights in this report may provide a helpful indication of storage system cost and performance targets. Many other existing resources can be used to determine the cost for, and technical viability of, specific storage types.[1][2][3]

1.2. Background and Genesis

The original work underlying this report, supported and funded by the U.S. Department of Energy (DOE), was developed in support of the California Energy Commission (CEC) Public Interest Energy Research (PIER) Program. The purpose of that work – documented in the report *Energy Storage Benefits and Market Analysis Handbook* (Sandia National Laboratories report #SAND2004-6177) – was to provide guidance for organizations seeking CEC co-funding for storage demonstrations. The approach used for selecting co-funding proposals emphasized demonstration of storage to be used for a specific *value proposition*. Furthermore, the CEC gave some preference to value propositions with more potential to have a positive impact.

1.3. Intended Audience

The intended audience for this document includes persons or organizations needing a framework for making first-cut or high-level estimates of benefits for a specific storage project and/or those seeking a high-level estimate of viable price points and/or maximum market potential for their products. Thus, the intended audience includes, in no particular order: electric utility planners and researchers, non-utility electricity service providers and load aggregators, electricity end users, electric utility regulators and policymakers, and storage project and technology developers, and vendors.

1.4. Analysis Philosophy

The methodologies used to estimate application-specific values for benefits and market potential are intended to balance a general preference for precision with the cost to perform rigorous financial assessments and to make rigorous market assessments. Much of the data needed for a more rigorous approach is proprietary or otherwise unavailable; is too expensive, does not exist in a usable form, or does not exist at all. It is also challenging to establish extremely credible generic values for benefits when those values are somewhat-to-very specific to region and circumstances. Similarly, making national estimates of maximum market potential using limited data requires many assumptions that are established using a combination of informal surveys of experts, subjectivity, and authors' familiarity with the subject. Nonetheless, despite those challenges, this report includes just such estimates of generic, application-specific values for benefits and maximum market potential.

Given the diversity of California's generation mix, load types and sizes, regions, weather conditions, *etc.*, it was assumed to be a reasonable basis for estimating national values. The application-specific benefit estimates are especially California-centric. Also, maximum market potential estimates developed for California are extrapolated to estimate values for the entire country. (See Section 4 for details.)

Although the methodology used to estimate benefits and maximum market potential involves some less than rigorous analysis, it was the authors' intention to make reasonable attempts to document assumptions and methodologies used so that the evaluation is as transparent and auditable as is practical. This gives the necessary information to readers and analysts so that they may consider the merits and appropriateness of data and methodologies used in this report. To the extent that superior data or estimates are available, and/or a superior or preferred estimation methodology exists, those should be used *in lieu* of the assumptions and approaches in this report.

Similarly, given the generic nature of the benefit estimates, for specific situations or projects it is prudent to undertake a more circumstance-specific and possibly more detailed evaluation than is possible using the assumptions and estimates in this guide.

1.4.1. Application *versus* Benefit

It is important to note the distinction made in this document between applications and benefits. In general terms, an *application* is a *use* whereas a *benefit* connotes a *value*. In many cases, a benefit is quantified in terms of the monetary or financial value. Of course, some qualitative benefits – such as the 'goodness' of reduced noise and improved aesthetics – may not be readily quantifiable and/or expressed in financial terms.

1.4.2. Internalizable Benefits

The concept of an internalizable benefit is an important theme for this report. An internalizable benefit is one that can be 'captured', 'realized', or received by a given stakeholder or stakeholders. An internalizable financial benefit takes the form of revenue or reduced cost. A benefit is most readily internalizable if there is a price associated with it. (Some refer to a benefit for which there is an established financial value – especially in the form of a price – as a benefit that is 'monetized'.)

An example of a readily internalized benefit is electricity bill reduction that accrues to a utility customer who uses storage to reduce on-peak a) energy cost and b) demand charges. In that example, the benefit is a function of a) the amount of energy and the level of demand involved and b) the on-peak and the off-peak prices for energy and the on-peak demand charge.

Continuing with the example; consider that the same customer-owned and -operated storage could also reduce or delay the need (*and cost*) for additional utility-owned transmission and distribution (T&D) capacity. The resulting 'T&D upgrade deferral' benefit (*i.e.*, reduced, deferred or avoided cost) though real, cannot be directly internalized by the utility customer who installs the storage. That is because there is no established 'price' associated with reducing the need for a *specific* T&D capacity upgrade (*i.e.*, the utility's avoided cost cannot be shared with end users who take actions that defer/reduce the need and cost for a T&D upgrade). Rather, the resulting T&D upgrade deferral benefit is internalized by the utility and/or the utility's ratepayers as a group (in the form of reduced, deferred, or avoided price increase).

1.4.3. Societal Benefits

Although not addressed in detail in this report, it is important to consider some important storage-related benefits that accrue, in part or in whole, to electric utility customers as a group and/or to society at large. Three examples of possible storage-related societal benefits are the integration of more renewables, more effectively; reduced air emissions from generation; and improved utilization of grid assets (*i.e.*, generation and T&D equipment).

In most cases, societal benefits are accompanied by an internalizable or partially internalizable benefit. Consider an example: A utility customer uses storage to reduce on-peak energy use. An internalizable benefit accrues to that customer in the form of reduced cost; however, other societal benefits may accrue to utility customers as a group and/or to society as a whole. For example, reduced peak demand could lead to reduced need for generation and transmission capacity, reduced air emissions, and a general improvement of businesses' cost competitiveness.

This topic is especially important for lawmakers, electric utility regulators, energy and electricity policymakers and policy analysts, and storage advocates as laws, regulations, and policies that could affect prospects for increased storage use are developed.

1.5. Grid and Utility-related General Considerations

Applications described in this report affect the electric supply system and the T&D system – known collectively as 'the grid'. This subsection characterizes several important considerations and topics related to the electric grid. Those topics are presented here as context for results presented throughout the rest of this report.

1.5.1. Real Power *versus* Apparent Power

For the purposes of this document, units of kW and MW (real or true power) are used universally when kVA and MVA (apparent power) may be the more technically correct units. Given the degree of precision possible for market potential and financial benefit estimation, the distinction between these units has relatively little impact on most results.*

1.5.2. Ancillary Services

Some possible uses of storage are typically classified as ancillary services. The electric utility industry has a specific definition of ancillary services. (See Appendix A for brief overview of ancillary services.)

Three specific ancillary services are explicitly addressed in this report: 1) area regulation, 2) electric supply reserve capacity, and 3) voltage support. Although not always categorized as an ancillary service, in this guide load following is also included in the ancillary services category.

1.5.3. Electricity Transmission and Distribution

The electric utility transmission and distribution (T&D) system comprises three primary subsystems: 1) transmission, 2) subtransmission, and 3) distribution, as described below. Several storage applications involve benefits associated with one or more of these subsystems.

Electricity Transmission – Electricity transmission is the backbone of the electric grid. Transmission wires, transformers, and control systems transfer electricity from supply sources (generation or electricity storage) to utility distribution systems. Often, the transmission system is used to send large amounts of electricity over relatively long distances. In the U.S., transmission system operating voltages generally range from 200 kV (200,000 V) to 500 kV (500,000 V). Transmission systems typically transfer the equivalent of 200 MW to 500 MW. Most transmission systems use alternating current (AC), though some larger, longer transmission corridors employ high-voltage direct current (DC).

Electricity Subtransmission – Relative to transmission, subtransmission transfers smaller amounts of electricity, at lower operating voltages, over shorter distances. Normally, subtransmission voltages fall within the range of 50 kV (50,000 V) to 100 kV (100,000 V) with 69 kV (69,000 V) being somewhat common.

Electricity Distribution – Electricity distribution is the part of the electric grid that delivers electricity to end users. It is connected to the subtransmission system which, in turn, is connected to the transmission system and the electric supply system (generation). Relative to electricity transmission, the distribution system is used to send relatively small amounts of electricity over relatively short distances. In the U.S., distribution system operating voltages generally range from a few thousand volts to 50 kV. Typical power transfer capacities range from a few tens of MW for substation transformers to as few as tens of kW for very small circuits.

Two applications addressed in this report apply only to the transmission system: 1) transmission support and 2) transmission congestion relief.

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* In practice, there are important technical and cost differences between true power (kW or MW) and apparent power (kVA or MVA). Various load types reduce the effectiveness of the grid by, for example, injecting harmonic currents or by increasing reactive power flows. As a general indication of the magnitude of the difference, consider this example: a power system serves 10 MW of peak load (true power). During times when load is at its peak, the 'power factor' may drop to 0.85. Given that power factor, the T&D equipment should have an apparent power rating of at least 10 MW/0.85 = 11.76 MVA.

1.5.4. Utility Regulations and Rules

Some of the benefits characterized in this report may not apply in any particular circumstance because provisions of applicable rules or regulations may not provide the means for a given stakeholder to internalize the benefit. For example, one application characterized is demand charge reduction for utility customers; but, if the customer is not eligible for demand charges, then that application does not apply. Consider another example: A utility customer with 100 kW may not be allowed to participate in the market for ancillary services (without some type of 'load aggregation') because the minimum capacity required is 1 MW.

1.5.5. Utility Financials: Fixed Charge Rate

Some important applications involve storage used to reduce the need to own other utility equipment – generation, transmission, and/or distribution. The cost *reduction* is often referred to as an *avoided cost*.

For investor-owned utilities (IOUs), the avoided cost of equipment ownership is primarily consists of six elements: 1) interest payments for bond holders, 2) equity returns (dividends) for stock owners, 3) annual return of principal or depreciation, 4) income taxes, 5) property taxes, and 6) insurance.

Though circumstances can vary, the avoided cost for municipal utilities (munis) and co-operative utilities (co-ops) includes annual interest payments and 'return of capital' (*i.e.*, amortization). Cooperatives' cost may also be subject to property taxes and insurance.

When estimating benefits related to deferred or avoided cost for utility equipment ownership, it is usually necessary to first estimate the *annual* cost. Utilities often refer to this annual avoided cost as the *annual revenue requirement* because it is equal to the annual revenue needed (from utility customers) to cover the full cost of owning the equipment.

> Although the topic is beyond the scope of this guide, readers should note the important distinction between—
>
> 1) avoided cost for ownership of a capital *investment* (in this case, utility equipment)
>
> and
>
> 2) avoided cost for an *expense* incurred due to equipment operation, such as the cost for fuel or variable maintenance.
>
> The distinction is important because investor-owned utilities' profit is based on investments made in equipment, whereas expenses are pass throughs to end users as-is (*i.e.*, without profit).

In this guide, a fixed charge rate is used to estimate *annual* avoided cost of equipment ownership. The fixed charge rate reflects the six elements of utility equipment cost listed above (annual interest and equity payments, *etc.*) as applicable for a given utility.

Annual avoided cost is calculated by multiplying the equipment's total *installed* cost by a utility-specific fixed charge rate. (Installed cost includes all costs incurred until equipment enters service, including equipment purchase price, design, installation, commissioning, *etc.*)

Note that the annual avoided cost calculated using the fixed charge rate is equivalent to an annuity payment involving a series of equal annual payments over the equipment's life, similar to a mortgage. Given that the annual avoided cost is expressed as equal annual payments, it is often referred to as a 'levelized' cost.

Consider an example: A new storage system costing $500,000 is installed. Given the utility financial structure and the expected life of the storage system, the utility financial group calculates the fixed charge rate for the equipment to be 0.11. So, the full 'capital carrying charges' incurred to own the storage plant (without regard to energy charging cost and other variable expenses) is $500,000 × 0.11 = $55,000 per year for each year during the expected life of the storage plant. (A fixed charge rate of 0.11 is the standard value used in this guide.)

1.6. Standard Assumption Values

Standard assumption values established for this guide are used to make high-level, generic estimates of financial benefits and maximum market potential for storage. Key standard assumption values are those provided for financial criteria and for storage discharge duration, power rating, and maximum market potential.

Certainly, to one extent or another, establishing such generic values requires subjectivity, speculation, simplifying assumptions, and/or generalizations. So, for any particular circumstance or situation, analysts are encouraged to use circumstance-specific assumptions and/or additional or superior information to establish superior values instead of the generic assumptions, as appropriate. To the extent possible, the rationale and underlying assumptions used to establish standard assumption values are presented and described in this report.

1.6.1. Standard Assumption Values for Financial Calculations

The following standard assumption values are used in this report to generalize and to simplify the calculations used as examples.

1.6.1.1. Storage Project Life

A storage project life of 10 years is assumed for lifecycle financial evaluations. That is an especially important standard assumption value for a variety of reasons. Clearly, using any one value is suboptimal because, if nothing else, each storage type and system may have a different life and each circumstance is different. Important factors affecting storage life also include the way(s) and amount that storage is used and the frequency and quality of storage system maintenance.

Given such considerations, without selecting one standard assumption for storage project life, it is conceivable that many estimates would have to be made for each benefit. Estimating benefits for various timeframes would add complexity to the evaluations and would yield results that are unwieldy and challenging to report. Furthermore, making numerous estimates for each benefit would require more resources than were allocated for this report.

Although the selection of 10 years is may seem somewhat arbitrary, there was a rationale for doing so. First, though a 10-year life is too short for compressed-air energy storage (CAES) and pumped hydro, it may be generous for the other storage types, given their somewhat-to-very limited record. Additionally, estimates of benefits accruing over periods of 10 to 20 years may not be credible and/or precise, given expected changes to and increasing uncertainty in the electricity marketplace. In fact, given that uncertainty, there is even a chance that some of the benefits may not even exist 10 or 20 years from now. Finally, when accounting for the time value of money, a significant majority of benefits accrue in the first 10 years.

Consider also that, for most benefits, there may be fairly straightforward ways to adjust benefit estimates to accommodate timeframes that are longer than the 10 years assumed. Section 1.6.1.4 provides an indication of a simplified way to accommodate a lifecycle other than 10 years.

1.6.1.2. Price Escalation

A general price escalation of 2.5% per year is assumed for the analysis in this guide. Electric energy and capacity costs and prices are assumed to escalate at that rate during the storage plant's financial life.

1.6.1.3. Discount Rate for Present Worth Calculations

An annual discount rate of 10.0% is used for making present worth (PW) calculations to estimate lifecycle benefits.

1.6.1.4. Present Worth Factor

The simplified approach described below for estimating the present worth (PW) of a stream of annual expenses or revenues is used throughout this guide. It is intended to provide a simple, auditable, and flexible way to estimate PW. Detailed treatment of more sophisticated financial calculations is beyond the scope of this guide.

Present worth calculations are made using these standard assumptions:

- 2.5% per year annual price/cost escalation
- 10.0% per year discount rate
- 10-year storage equipment life
- Mid-year convention

The PW factor is calculated based on these assumptions. That value is used to estimate present worth based on the value in the first year of operation. Given the standard assumption values of 2.5% cost/price escalation rate, 10% discount rate, and 10-year storage system life, the standard assumption value for the PW factor is 7.17.

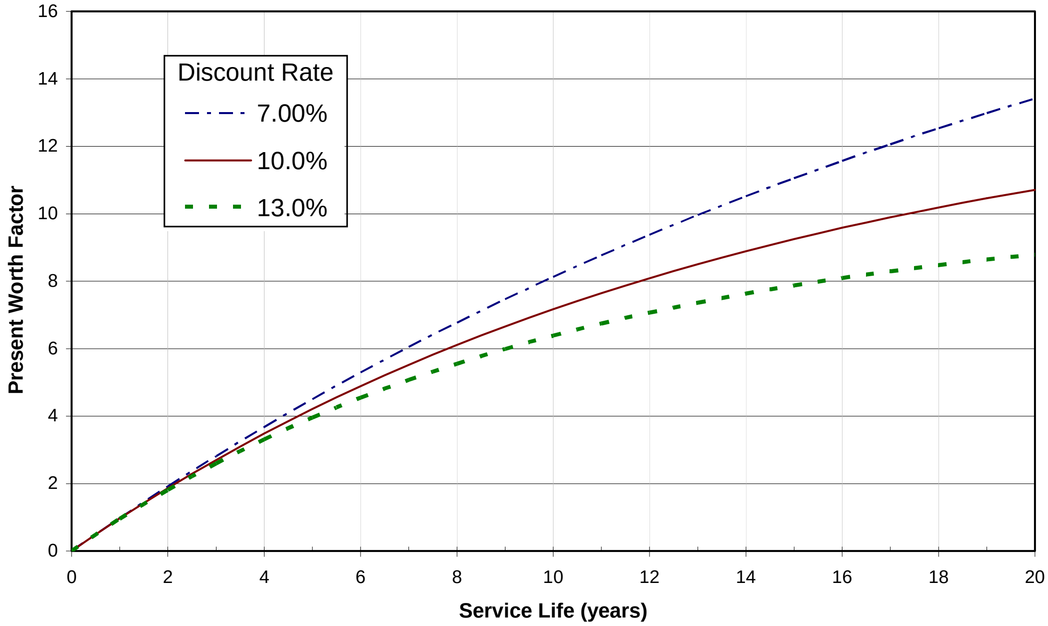
Consider an example of how the PW factor is used: For an annual/first year benefit of \$100,000, the estimated lifecycle benefit is \$100,000 × 7.17 = \$717,000 (present worth) for 10 years.

The equation for the PW factor for a 10-year service life is as follows:

$$\text{PW Factor} = \sum_{i=1}^{10} \frac{(1+e)^{i-.5}}{(1+d)^{i-.5}}$$

e = annual price escalation rate (%/year)
d = discount rate (%/year)
i = year

Figure 1 shows PW factors for three discount rates, assuming a cost escalation of 2.5% per year. (Note that the value of 'I' is calculated at mid-year.) For a given life/discount rate combination, the PW factor represents the present worth for a sum of a stream of annual values. Table 1 includes PW factors for Years 5 to 20 for a discount rate of 10% (shown with the solid line). The figure allows for quick comparisons of annually recurring costs and benefits for various storage project lifecycles and discount rates.



Escalation Rate: 2.5%/yr. Mid Year Convention.

Figure 1. Present worth factors.

Table 1. Present Worth Factors, 2.5% Escalation, 10% Discount Rate

Year	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
PW Factor	4.21	4.89	5.52	6.11	6.66	7.17	7.65	8.09	8.5	8.89	9.25	9.58	9.9	10.2	10.5	10.7

Consider another example: Assume that a storage plant will operate for 20 years and that it has a first-year operating cost of $100,000 which is expected to escalate at a rate of 2.5% per year. If the owner uses a 13% discount rate, then the PW factor is about 8.80 (as shown in Figure 1). So, the 20-year present worth of all operating costs (before taxes) is

$\$100{,}000 \times 8.80 = \$880{,}000.$

Implicit in this approach is the assumption that annual benefits for all years considered (10 in this case) are the same as the first year, except that the cost or price escalates at 2.5%. If that approach is not appropriate, then an actual cash flow evaluation may be required to estimate the lifecycle benefits.

1.6.1.5. Fixed Charge Rate

The standard assumption value for fixed charge rate – which applies to utilities only – is 0.11. The fixed charge rate is used as follows: Consider utility equipment whose installed cost is $500,000. The utility's *annual* revenue requirement (and avoided cost) is

$\$500{,}000 \times 0.11 = \$55{,}000\text{/year}.$

1.7. Results Summary

Key study results are summarized in Table 2. The table contains three criteria for the 17 primary benefits characterized in this guide, for California and for the U.S.: 1) benefit, 2) potential, and 3) economy. The 'benefit' value indicates the present worth of the respective benefit type for 10 years (assuming 2.5% inflation and 10% discount rate). 'Potential' indicates the maximum market potential for the respective benefit over 10 years. 'Economy' reflects the total value of the benefit given the maximum market potential.

Table 2. Primary Results Summary — Benefits, Maximum Market Potential, and Maximum Economic Value

#	Benefit Type	Benefit ($/kW)**		Potential (MW, 10 Years)		Economy ($Million)†	
		Low	High	CA	U.S.	CA	U.S.
1	Electric Energy Time-shift	400	700	1,445	18,417	795	10,129
2	Electric Supply Capacity	359	710	1,445	18,417	772	9,838
3	Load Following	600	1,000	2,889	36,834	2,312	29,467
4	Area Regulation	785	2,010	80	1,012	112	1,415
5	Electric Supply Reserve Capacity	57	225	636	5,986	90	844
6	Voltage Support	400		722	9,209	433	5,525
7	Transmission Support	192		1,084	13,813	208	2,646
8	Transmission Congestion Relief	31	141	2,889	36,834	248	3,168
9.1	T&D Upgrade Deferral 50th percentile††	481	687	386	4,986	226	2,912
9.2	T&D Upgrade Deferral 90th percentile††	759	1,079	77	997	71	916
10	Substation On-site Power	1,800	3,000	20	250	47	600
11	Time-of-use Energy Cost Management	1,226		5,038	64,228	6,177	78,743
12	Demand Charge Management	582		2,519	32,111	1,466	18,695
13	Electric Service Reliability	359	978	722	9,209	483	6,154
14	Electric Service Power Quality	359	978	722	9,209	483	6,154
15	Renewables Energy Time-shift	233	389	2,889	36,834	899	11,455
16	Renewables Capacity Firming	709	915	2,889	36,834	2,346	29,909
17.1	Wind Generation Grid Integration, Short Duration	500	1,000	181	2,302	135	1,727
17.2	Wind Generation Grid Integration, Long Duration	100	782	1,445	18,417	637	8,122

*Hours unless indicated otherwise. min. = minutes. sec. = seconds.
**Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.
†Based on potential (MW, 10 years) times average of low and high benefit ($/kW).
†† Benefit for *one year*. However, storage could be used at more than one location at different times for similar l

2. Electric Energy Storage Technology Overview

A general introduction to energy storage technology is provided as context for the applications and benefits addressed in this guide. Storage technology and subsystems are subjects covered in detail by other studies and reports. Section 2.1 provides a brief description of storage types. Sections 2.2 through 2.20 briefly describe important storage characteristics. Note that the order in which these characteristics are presented is not meant to imply order of importance.

2.1. Overview of Storage Types

2.1.1. Electrochemical Batteries

Electrochemical batteries consist of two or more electrochemical cells. The cells use chemical reaction(s) to create a flow of electrons – electric current. Primary elements of a cell include the container, two electrodes (anode and cathode), and electrolyte material. The electrolyte is in contact with the electrodes. Current is created by the oxidation-reduction process involving chemical reactions between the cell's electrolyte and electrodes.

When a battery discharges through a connected load, electrically charged ions in the electrolyte that are near one of the cell's electrodes supply electrons (oxidation) while ions near the cell's other electrode accept electrons (reduction), to complete the process. The process is reversed to charge the battery, which involves ionizing of the electrolyte.

An increasing number of chemistries are used for this process. More familiar ones include lead-acid, nickel-cadmium (NiCad), lithium-ion (Li-ion), sodium/sulfur (Na/S), zinc/bromine (Zn/Br), vanadium-redox, nickel-metal hydride (Ni-MH), and others.

2.1.1.1. Flow Batteries

Some electrochemical batteries (*e.g.*, automobile batteries) contain electrolyte in the same container as the cells (where the electrochemical reactions occur). Other battery types – called flow batteries – use electrolyte that is stored in a separate container (*e.g.*, a tank) outside of the battery cell container. Flow battery cells are said to be configured as a 'stack'.

When flow batteries are charging or discharging, the electrolyte is transported (*i.e.*, pumped) between the electrolyte container and the cell stack. Vanadium redox and Zn/Br are two of the more familiar types of flow batteries. A key advantage to flow batteries is that the storage system's discharge duration can be increased by adding more electrolyte (and, if needed to hold the added electrolyte, additional electrolyte containers). It is also relatively easy to replace a flow battery's electrolyte when it degrades.

2.1.2. Capacitors

Capacitors store electric energy as an electrostatic charge. An increasing array of larger capacity capacitors have characteristics that make them well-suited for use as energy storage.[*] They store significantly more electric energy than conventional capacitors. They are especially well-suited

[*] Trade names for such devices include Supercapacitor and Ultracapacitor.

to being discharged quite rapidly, to deliver a significant amount of energy over a short period of time (*i.e.*, they are attractive for high-power applications that require short or very short discharge durations).

2.1.3. Compressed Air Energy Storage

Compressed air energy storage (CAES) involves compressing air using inexpensive energy so that the compressed air may be used to generate electricity when the energy is worth more. To convert the stored energy into electric energy, the compressed air is released into a combustion turbine generator system. Typically, as the air is released, it is heated and then sent through the system's turbine. As the turbine spins, it turns the generator to generate electricity.

For larger CAES plants, compressed air is stored in underground geologic formations, such as salt formations, aquifers, and depleted natural gas fields. For smaller CAES plants, compressed air is stored in tanks or large on-site pipes such as those designed for high-pressure natural gas transmission (in most cases, tanks or pipes are above ground).

2.1.4. Flywheel Energy Storage

Flywheel electric energy storage systems (flywheel storage or flywheels) include a cylinder with a shaft that can spin rapidly within a robust enclosure. A magnet levitates the cylinder, thus limiting friction-related losses and wear. The shaft is connected to a motor/generator. Electric energy is converted by the motor/generator to kinetic energy. That kinetic energy is stored by increasing the flywheel's rotational speed. The stored (kinetic) energy is converted back to electric energy via the motor/generator, slowing the flywheel's rotational speed.

2.1.5. Pumped Hydroelectric

Key elements of a pumped hydroelectric (pumped hydro) system include turbine/generator equipment, a waterway, an upper reservoir, and a lower reservoir. The turbine/generator is similar to equipment used for normal hydroelectric power plants that do not incorporate storage.

Pumped hydro systems store energy by operating the turbine/generator in reserve to pump water uphill or into an elevated vessel when inexpensive energy is available. The water is later released when energy is more valuable. When the water is released, it goes through the turbine which turns the generator to produce electric power.

2.1.6. Superconducting Magnetic Energy Storage

The storage medium in a superconducting magnetic energy storage (SMES) system consists of a coil made of superconducting material. Additional SMES system components include power conditioning equipment and a cryogenically cooled refrigeration system.

The coil is cooled to a temperature below the temperature needed for superconductivity (the material's 'critical' temperature). Energy is stored in the magnetic field created by the flow of direct current in the coil. Once energy is stored, the current will not degrade, so energy can be stored indefinitely (as long as the refrigeration is operational).

2.1.7. Thermal Energy Storage

There are various ways to store thermal energy. One somewhat common way that thermal energy storage is used involves making ice when energy prices are low so the cold that is stored can be used to reduce cooling needs – especially compressor-based cooling – when energy is expensive.

2.2. Storage System Power and Discharge Duration

When characterizing the rating of a storage system, the two key criteria to address are power and energy. *Power* indicates the *rate* at which the system can supply energy. *Energy* relates to the *amount* of energy that can be delivered to loads. In practical terms, the amount of energy stored determines the amount of time that the system can discharge at its rated power (output), hence the term *discharge duration*.

Storage power and energy are described in more detail below. For detailed coverage of the topic, readers should refer to a report developed by the Electric Power Research Institute (EPRI) and the DOE entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program*.[4]

2.2.1. Storage Power

A storage system's power rating is assumed to be the system's nameplate power rating under normal operating conditions. Furthermore, that rating is assumed to represent the storage system's *maximum* power output under *normal* operating conditions. In this guide, the normal discharge rate used is commonly referred to as the system's 'design' or 'nominal' (power) rating. Generic application-specific power requirements are summarized in Table 4 (in Section 3).

2.2.1.1. Storage 'Emergency' Power Capability

Some types of storage systems can discharge at a relatively high rate (*e.g.*, 1.5 to 2 times their nominal rating) for relatively short periods of time (*e.g.*, several minutes to as much as 30 minutes). One example is storage systems involving an Na/S battery, which is capable of producing two times its rated (normal) output for relatively short durations.[5]

That feature – often referred to as the equipment's 'emergency' rating – is valuable if there are circumstances that occur infrequently that involve an urgent need for relatively high power output, for relatively short durations.

Importantly, while discharging at the higher rate, storage efficiency is reduced (relative to efficiency during discharge at the nominal discharge rate), and storage equipment damage increases (compared to damage incurred at the normal discharge rate).

So, in simple terms, storage with emergency power capability could be used to provide the nominal amount of power required to serve a regularly occurring need (*e.g.*, peak demand reduction) while the same storage could provide additional power for urgent needs that occur infrequently and that last for a few to several minutes at a time.

2.2.2. Storage Discharge Duration

Discharge duration is the amount of time that storage can discharge at its rated output (power) without recharging. Discharge duration is an important criterion affecting the technical viability of a given storage system for a given application and storage plant cost.

To the extent possible, this document includes generalized guidance about the necessary discharge duration for specific applications. Application-specific guidance and standard assumption values are provided in their respective subsections, below. Application-specific discharge durations and the assumptions used to establish them are summarized in Table 5 (in Section 3).

2.3. Energy and Power Density

Power density is the amount of power that can be delivered from a storage system with a given volume or mass. Similarly, energy density is the amount of energy that can be stored in a storage device that has a given volume or mass. These criteria are important in situations for which space is valuable or limited and/or if weight is important.

2.4. Storage System Footprint and Space Requirements

Closely related to energy and power density are footprint and space requirements for energy storage. Depending on the storage technology, floor area and/or space constraints may indeed be a challenge, especially in heavily urbanized areas.

2.5. Storage System Round-trip Efficiency

All energy transfer and conversion processes have losses. Energy storage is no different. Storage system round-trip efficiency (efficiency) reflects the amount of energy that comes out of storage relative to the amount put into the storage.

Typical values for efficiency include the following: 60% to 75% for conventional electrochemical batteries; 75% to 85% for advanced electrochemical batteries; 73% to 80% for CAES; 75% to 78% for pumped hydro; 80% to 90% for flywheel storage; and 95% for capacitors and SMES.[6][7]

2.6. Storage Operating Cost

Storage total operating cost (as distinct from plant *capital* cost or plant financial carrying charges) consists of two key components: 1) energy-related costs and 2) operating costs not related to energy. Non-energy operating costs include at least four elements: 1) labor associated with plant operation, 2) plant maintenance, 3) equipment wear leading to loss-of-life, and 4) decommissioning and disposal cost (addressed in Section 2.20).

2.6.1. Charging Energy-Related Costs

The energy cost for storage consists of all costs incurred to purchase energy used to charge the storage, including the cost to purchase energy needed to make up for (round trip) energy losses. An example: For a storage system with 75% efficiency, if the unit price for energy used for charging is 4¢/kWh, then the plant energy cost is

4¢/kWh ÷ 0.75 = 5.33¢/kWh.

2.6.2. Labor for Plant Operation

In some cases, labor may be required for storage plant operation. *Fixed* labor costs are the same magnitude irrespective of how much the storage is used. *Variable* labor costs are proportional to the frequency and duration of storage use. In many cases, labor is required to operate larger storage facilities and/or ‘blocks’ of aggregated storage capacity whereas little or no labor may be needed for smaller/distributed systems that tend to be designed for autonomous operation. No explicit value is ascribed to this criterion, due in part to the wide range of labor costs that are possible given the spectrum of storage types and storage system sizes.

2.6.3. Plant Maintenance

Plant maintenance costs are incurred to undertake normal, scheduled, and unplanned repairs and replacements for equipment, buildings, grounds, and infrastructure. *Fixed* maintenance costs are the same magnitude irrespective of how much the storage is used. *Variable* maintenance costs are proportional to the frequency and duration of storage use. Plant maintenance costs are highly circumstance-specific and are not addressed explicitly in this report.

2.6.4. Replacement Cost

If specific equipment or subsystems within a storage system are expected to wear out during the expected life of the system, then a ‘replacement cost’ will be incurred. In such circumstances, a ‘sinking fund’ is needed to accumulate funds to pay for replacements when needed. That replacement cost is treated as a variable cost (*i.e.,* the total cost is spread out over each unit of energy output from the storage plant). Replacement cost is highly technology- and circumstance-specific and is not addressed explicitly in this report. (See Appendix B for an example calculation of equipment replacement cost.)

2.6.5. Variable Operating Cost

A storage system’s total *variable* operating cost consists of applicable non-energy-related variable operating costs *plus* plant energy cost, possibly including charging energy, labor for plant operation, variable maintenance, and replacement costs. Variable operating cost is a key factor affecting the cost-effectiveness of storage. It is especially important for ‘high-use’ value propositions involving many charge-discharge cycles.

Ideally, storage for high-use applications should have relatively high or very high efficiency and relatively low variable operating cost. Otherwise, the total cost to charge then discharge the storage is somewhat-to-very likely to be higher than the benefit. That can be a significant challenge for some storage types and value propositions.

Consider the example illustrated in Figure 2, which involves a 75% efficient storage system with a non-energy-related variable operating cost of 4¢/kWh_{out}. If that storage system is charged with energy costing 4¢/kWh_{in}, then the total variable operating cost – for energy output – is about 9.33¢/kWh_{out}.

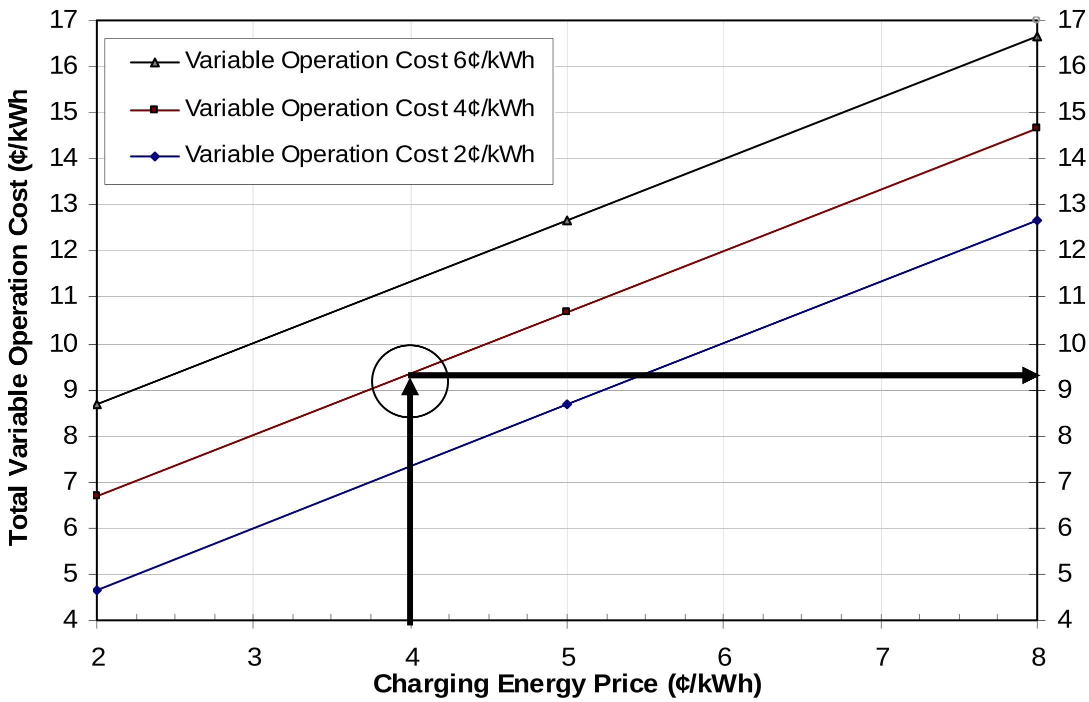


Figure 2. Storage total variable operation cost for 75% storage efficiency.

2.7. Lifetime Discharges

To one extent or another, most energy storage media degrade with use (*i.e.*, during each charge-discharge cycle). The rate of degradation depends on the type of storage technology, operating conditions, and other variables. This is especially important for electrochemical batteries.

For some storage technologies – especially batteries – the extent to which the system is emptied (discharged) also affects the storage media's useful life. Discharging a small portion of stored energy is a 'shallow' discharge and discharging most or all of the stored energy is a 'deep' discharge. For these technologies, a shallow discharge is less damaging to the storage medium than a deep discharge.

Note that many battery vendors can produce storage media with extra service life (relative to the baseline product) to accommodate additional charge-discharge cycles and/or deeper discharges. Of course, there is usually a corresponding incremental cost for the superior performance. To the extent that the storage medium degrades and must be replaced during the expected useful life of the storage system, the cost for that replacement must be added to the variable operating cost of the storage system.

2.8. Reliability

Like power rating and discharge duration, storage system reliability requirements are circumstance-specific. Little guidance is possible. The project design engineer is responsible for designing a plant that provides enough power and that is as reliable as necessary to serve the specific application.

2.9. Response Time

Storage response time is the amount of time required to go from no discharge to full discharge. At one extreme, under almost all conditions, storage has to respond quite rapidly if used to provide capacity on the margin *in lieu* of T&D capacity. That is because the output from T&D equipment (*i.e.,* wires and transformers) changes nearly instantaneously in response to demand.

In contrast, consider storage used *in lieu* of generation capacity. That storage does not need to respond as quickly because generation tends to respond relatively slowly to demand changes. Specifically, some types of generation – such as engines and combustion turbines – take several seconds to many minutes before generating at full output. For other generation types, such as those fueled by coal and nuclear energy, the response time may be hours.

Most types of storage have a response time of several seconds or less. CAES and pumped hydroelectric storage tend to have a slower response, though they still respond quickly enough to serve several important applications.

2.10. Ramp Rate

An important storage system characteristic for some applications is the ramp rate – the rate at which power output can change. Generally, storage ramp rates are rapid (*i.e.,* output can change quite rapidly); pumped hydro is the exception. Power devices with a slow response time tend also to have a slow ramp rate.

2.11. Charge Rate

Charge rate – the rate at which storage can be charged – is an important criterion because, often, modular energy storage (MES) must be recharged so it can serve load during the next day. If storage cannot recharge quickly enough, then it will not have enough energy to provide the necessary service. In most cases, storage charges at a rate that is similar to the rate at which it discharges. In some cases, storage may charge more rapidly or more slowly, depending on the capacity of the power conditioning equipment and the condition and/or chemistry and/or physics of the energy storage medium.

2.12. Energy Retention and Standby Losses

Energy retention time is the amount of time that storage retains its charge. The concept of energy retention is important because of the tendency for some types of storage to self-discharge or to otherwise dissipate energy while the storage is not in use. In general terms, energy losses could be referred to as *standby* losses.

Storage that depends on chemical media is prone to self-discharge. This self-discharge is due to chemical reactions that occur while the energy is stored. Each type of chemistry is different, both in terms of the chemical reactions involved and the rate of self-discharge. Storage that uses mechanical means to store energy tends to be prone to energy dissipation. For example, energy stored using pumped hydroelectric storage may be lost to evaporation. CAES may lose energy due to air escaping from the reservoir.

To the extent that storage is prone to self-discharge or energy dissipation, retention time is reduced. This characteristic tends to be less important for storage that is used frequently. For storage that is used infrequently (*i.e.*, is in standby mode for a significant amount of time between uses), this criterion may be very important.

2.13. Transportability

Transportability can be an especially valuable feature of storage systems for at least two reasons. First, transportable storage can be (re)located where it is needed most and/or where benefits are most significant. Second, some locational benefits only last for one or two years. Perhaps the most compelling example of the latter is T&D deferral, as discussed in detail in Section 3. Given those considerations, transportability may significantly enhance the prospects that lifecycle benefits will exceed lifecycle cost.

2.14. Modularity

One attractive feature of modular energy storage is the flexibility that system 'building blocks' provide. Modularity allows for more optimal levels and types of capacity and/or discharge duration because modular resources allow utilities to increase or decrease storage capacity, when and where needed, in response to changing conditions. Among other attractive effects, modular capacity provides attractive means for utilities to address uncertainty and to manage risk associated with large, 'lumpy' utility T&D investments.

2.15. Power Conditioning

To one extent or another, most storage types require some type of power conditioning (*i.e.*, conversion) subsystem. Equipment used for power conditioning – the power conditioning unit (PCU) – modifies electricity so that the electricity has the necessary voltage and the necessary form; either alternating current (AC) or direct current (DC). The PCU, in concert with an included control system, must also synchronize storage output with the oscillations of AC power from the grid.

Output from storage with relatively low-voltage DC output must be converted to AC with higher voltage before being discharged into the grid and/or before being used by most load types. In most cases, conversion from DC to AC is accomplished using a device known as an *inverter*.

For storage requiring DC input, the electricity used for charging must be converted from the form available from the grid (*i.e.*, AC at relatively high voltage) to the form needed by the storage system (*e.g.*, DC at lower voltage). That is often accomplished via a PCU that can function as a DC 'power supply'.

2.16. Power Quality

Although requirements for applications vary, the following storage characteristics may or may not be important. To one extent or another, they are affected by the PCU used and/or they drive the specifications for the PCU. In general, higher quality power (output) costs more.

2.16.1. Power Factor

Although detailed coverage of the concept of power factor is beyond the scope of this report, it is important to be aware of the importance of this criterion. At a minimum, the power output from storage should have an acceptable power factor, where acceptable is somewhat circumstance-specific. For some applications, the storage system may be called upon to provide power with a variable power factor. (See Appendix C for more details about this consideration.)

2.16.2. Voltage Stability

In most cases, it is important for storage output voltage to remain somewhat-to-very constant. Depending on the circumstances, voltage can vary; though, it should probably remain within about 5% to 8% of the rated value.

2.16.3. Waveform

Assuming that storage output is AC, in most cases, the waveform should be as close as possible to that of a sine wave. In general, higher quality PCUs tend to have waveforms that are quite close to that of a sine wave whereas output from lower quality PCUs tends to have a waveform that is somewhat square.

2.16.4. Harmonics

Harmonic currents in distribution equipment can pose a significant challenge. Harmonic currents are components of a periodic wave whose frequency is an integral multiple of the fundamental frequency. In this case, the fundamental frequency is the utility power line frequency of 60 Hz. So, for example, harmonic currents might exist with frequencies of 3 × 60 Hz (180 Hz) or 7 × 60 Hz (420 Hz). Total harmonic distortion (THD) is the contribution of all the individual harmonic currents to the fundamental.

2.17. Storage System Reactive Power Capability

One application (Voltage Support) and one incidental benefit (Power Factor Correction) described in this guide involve storage whose capabilities include absorbing and injecting reactive power (expressed in units of volt-Amperes reactive or VARs). This feature is commonly referred as VAR support. In most cases, storage systems by themselves do not have reactive power capability. For a relatively modest incremental cost, however, reactive power capability can be added to most storage system types. (See Appendix C for more details.)

2.18. Communications and Control

Storage used for most applications addressed in this report must receive and respond to appropriate control signals. In some cases, storage may have to respond to a dispatch control signal. In other cases, the signal may be driven by a price or prices. Storage response to a control signal may be a simple ramp up or ramp down of power output in proportion to the control signal. A more sophisticated response, requiring one or more control algorithms, may be needed. An example of that is storage used to respond to price signals or to accommodate more than one application.

2.19. Interconnection

If storage will be charged with energy from the grid or will inject energy into the grid, it must meet applicable interconnection requirements. At the distribution level, an important point of reference is the Institute of Electronics and Electrical Engineers (IEEE) Standard 1547.[8] Some states and utilities have more specific interconnection rules and requirements.

2.20. Decommissioning and Disposal Needs and Cost

Although not addressed explicitly in this report, in most cases there will be non-trivial decommissioning costs associated with almost any storage system. For example, eventually batteries must be dismantled and the chemicals must be removed. Ideally, dismantled batteries and their chemicals can be recycled, as is the case for the materials in lead-acid batteries. Ultimately, decommissioning-related costs should be included in the total cost to own and to operate storage.

3. Electric Energy Storage Applications

3.1. Introduction

This section characterizes 17 electric grid-related energy storage applications. Included in each characterization are a description of the application, an overview of application-specific technical considerations, and a summary of possible synergies with other applications. (Section 2 includes a brief characterization of several important storage system characteristics.) The 17 applications are grouped into five categories as shown in Table 3.

Table 3. Five Categories of Energy Storage Applications

Category 1 — Electric Supply
1. Electric Energy Time-shift
2. Electric Supply Capacity
Category 2 — Ancillary Services
3. Load Following
4. Area Regulation
5. Electric Supply Reserve Capacity
6. Voltage Support
Category 3 — Grid System
7. Transmission Support
8. Transmission Congestion Relief
9. Transmission & Distribution (T&D) Upgrade Deferral
10. Substation On-site Power
Category 4 — End User/Utility Customer
11. Time-of-use (TOU) Energy Cost Management
12. Demand Charge Management
13. Electric Service Reliability
14. Electric Service Power Quality
Category 5 — Renewables Integration
15. Renewables Energy Time-shift
16. Renewables Capacity Firming
17. Wind Generation Grid Integration

3.1.1. Power Applications *versus* Energy Applications

Although this report does not focus on specific storage technologies, it is helpful to be aware of the distinction between storage technologies classified as those that are best suited for *power* applications and those best suited to *energy* applications.

Power applications require high power output, usually for relatively short periods of time (a few seconds to a few minutes). Storage used for power applications usually has capacity to store fairly modest amounts of energy per kW of rated power output. Notable storage technologies that are especially well-suited to power applications include capacitors, SMES, and flywheels.

Energy applications are uses of storage requiring relatively large amounts of energy, often for discharge durations of many minutes to hours. So, storage used for energy applications must have a much larger energy storage reservoir than storage used for power applications. Storage technologies that are best suited to energy applications include CAES, pumped hydro, thermal energy storage, and most battery types.

3.1.2. Capacity Applications *versus* Energy Applications

Similar to the distinction between power applications and energy applications is the distinction between *capacity* applications and *energy* applications. In simple terms, capacity applications are those involving storage used to defer or to reduce the need for other equipment. For example, storage can be used to reduce the need for generation or T&D equipment. Depending on circumstances, capacity applications tend to require relatively limited amounts of energy discharge throughout the year.

As described above, energy applications involve storing a significant amount of electric energy to offset the need to purchase or to generate the energy when needed. Typically, energy-related applications require a relatively significant amount of energy to be stored and discharged throughout the year. An important consideration is that storage used for energy applications should be relatively efficient, or the cost incurred due to energy losses will offset a significant amount of the benefit. The same applies to non-energy-related variable operation cost.

Importantly, for investor-owned utilities (IOUs) capacity is generally treated like an *investment* whereas purchases of or generation of energy are typically thought of as an *expenses* involving variable operating cost and fuel-related costs. This distinction is especially important for investor-owned utilities given what is sometimes referred to as the *revenue requirement* method for establishing cost-of-service. Under that regulatory scheme utilities earn a rate of return (*i.e.*, profit) on *investments* in capital *equipment* whereas *expenses* are treated as a 'pass-through' to end users without any mark-up (*i.e.*, IOUs do not earn profit for *energy* provided).

3.1.3. Application-specific Power and Discharge Duration

Table 4 and Table 5 list application-specific standard assumption values for two key storage design criteria: 1) power rating and 2) discharge duration. Also shown are key underlying assumptions used when establishing those values. Table 4 lists application-specific, standard assumption values for storage power ratings and notes explaining the rationale used to make the estimates. Table 5 lists application-specific standard assumption values for discharge durations along with notes explaining the rationale used to make the estimates.

The standard assumption values used herein are intended to be generic. They were developed based on varying levels of engineering judgment and simplifying assumptions. Readers are encouraged to use case-specific assumptions and additional information, as needed and available, for more precise estimates of power ratings and discharge durations.

Table 4. Standard Assumption Values for Storage Power

#	Type	Storage Power		
		Low	High	Note
1	Electric Energy Time-shift	1 MW	500 MW	Low per ISO transaction min. (Can aggregate smaller capacity.) High = combined cycle gen.
2	Electric Supply Capacity	1 MW	500 MW	Same as above.
3	Load Following	1 MW	500 MW	Same as above.
4	Area Regulation	1 MW	40 MW	Low per ISO transaction min. Max is 50% of estimated CA technical potential of 80 MW.
5	Electric Supply Reserve Capacity	1 MW	500 MW	Low per ISO transaction min. (Can aggregate smaller capacity.) High = combined cycle gen.
6	Voltage Support	1 MW	10 MW	Assume distributed deployment, to serve Voltage support needs locally.
7	Transmission Support	10 MW	100 MW	Low value is for substransmission.
8	Transmission Congestion Relief	1 MW	100 MW	Low per ISO transaction min. (Can aggregate smaller capacity.) High = 20% of high capacity transmission.
9.1	T&D Upgrade Deferral 50th percentile	250 kW	5 MW	Low = smallest likely, High = high end for distribution & subtransmission.
9.2	T&D Upgrade Deferral 90th percentile	250 kW	2 MW	Same as above.
10	Substation On-site Power	1.5 kW	5 kW	Per EPRI/DOE Substation Battery Survey.
11	Time-of-use Energy Cost Management	1 kW	1 MW	Residential to medium sized commercial/industrial users.
12	Demand Charge Management	50 kW	10 MW	Small commercial to large commercial/industrial users.
13	Electric Service Reliability	0.2 kW	10 MW	Low = Under desk UPS. High = facility-wide for commercial/industrial users.
14	Electric Service Power Quality	0.2 kW	10 MW	Same as above.
15	Renewables Energy Time-shift	1 kW	500 MW	Low = small residential PV. High = "bulk" renewable energy fueled generation.
16	Renewables Capacity Firming	1 kW	500 MW	Same as above.
17.1	Wind Generation Grid Integration, Short Duration	0.2 kW	500 MW	Low = small residential turbine. High = larged wind farm boundary.
17.2	Wind Generation Grid Integration, Long Duration	0.2 kW	500 MW	Same as above.

Table 5. Standard Assumption Values for Discharge Duration

#	Type	Discharge Duration*		
		Low	High	Note
1	Electric Energy Time-shift	2	8	Depends on energy price differential, storage efficiency, and storage variable operating cost.
2	Electric Supply Capacity	4	6	Peak demand hours
3	Load Following	2	4	Assume: 1 hour of discharge duration provides approximately 2 hours of load following.
4	Area Regulation	15 min.	30 min.	Based on demonstration of Beacon Flywheel.
5	Electric Supply Reserve Capacity	1	2	Allow time for generation-based reserves to come on-line.
6	Voltage Support	15 min.	1	Time needed for a) system stabilization or b) orderly load shedding.
7	Transmission Support	2 sec.	5 sec.	Per EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications.[17]
8	Transmission Congestion Relief	3	6	Peak demand hours. Low value is for "peaky" loads, high value is for "flatter" load profiles.
9.1	T&D Upgrade Deferral 50th percentile	3	6	Same as Above
9.2	T&D Upgrade Deferral 90th percentile	3	6	Same as Above
10	Substation On-site Power	8	16	Per EPRI/DOE Substation Battery Survey.
11	Time-of-use Energy Cost Management	4	6	Peak demand hours.
12	Demand Charge Management	5	11	Maximum daily demand charge hours, per utility tariff.
13	Electric Service Reliability	5 min.	1	Time needed for a) shorter duration outages or b) orderly load shutdown.
14	Electric Service Power Quality	10 sec.	1 min.	Time needed for events ridethrough depends on the type of PQ challenges addressed.
15	Renewables Energy Time-shift	3	5	Depends on energy cost/price differential and storage efficiency and variable operating cost.
16	Renewables Capacity Firming	2	4	Low & high values for Renewable Gen./Peak Load correlation (>6 hours) of 85% & 50%.
17.1	Wind Generation Grid Integration, Short Duration	10 sec.	15 min.	For a) Power Quality (depends on type of challenge addressed) and b) Wind Intermittency.
17.2	Wind Generation Grid Integration, Long Duration	1	6	Backup, Time Shift, Congestion Relief.

*Hours unless indicated otherwise. Min. = minutes. Sec. = Seconds.

3.2. *Electric Supply Applications*

3.2.1. Application #1 — Electric Energy Time-shift

3.2.1.1. Application Overview

Electric energy time-shift (time-shift) involves purchasing inexpensive electric energy, available during periods when price is low, to charge the storage plant so that the stored energy can be used or sold at a later time when the price is high.

Entities that time-shift may be regulated utilities or non-utility merchants. Importantly, this application tends to involve purchase of inexpensive energy from the *wholesale* electric energy market for storage charging. When the energy is discharged, it could be resold via the wholesale market, or it may offset the need to purchase wholesale energy and/or to generate energy to serve end users' needs.

> It is common for those involved with storage to refer to energy time-shift transactions (using storage) as *arbitrage*. It is important to note, however, what arbitrage means to people involved in *finance*.
>
> A finance-centric definition of arbitrage is *the* simultaneous *purchase and sale of identical or equivalent commodities or other instruments across two or more markets in order to benefit from a discrepancy in their price relationship.*
>
> So, strictly speaking, *from a finance perspective* the term 'arbitrage' may be regarded as a misnomer when it is applied to most energy storage 'buy-low/sell-high' (time-shift) transactions. That is because the purchase and storage of electric energy occurs at a different time than sale or use of the energy. In fact, most often charging and discharging are separated by several hours.

3.2.1.2. Technical Considerations

For the time-shift application, the plant storage discharge duration is determined based on the incremental benefit associated with being able to make additional buy-low/sell-high transactions during the year *versus* the incremental cost for additional energy storage (discharge duration).

The standard assumption value for storage *minimum* discharge duration for this application is two hours. The upper boundary for discharge duration is defined by potential CAES or pumped hydroelectric facilities. For storage types that have a high incremental cost to increase the amount of energy that can be stored (*i.e.*, to increase discharge duration), the upper boundary is probably five or six hours — the typical duration of a utility's daily peak demand period.

Both storage (non-energy-related) variable operating cost and storage efficiency are especially important for this application because electric energy time-shift involves many possible transactions whose economic merit is based on the difference between the cost to purchase, store, and discharge energy (discharge cost) and the benefit derived when the energy is discharged. Any increase in variable operating cost or reduction of efficiency reduces the number of transactions for which the benefit exceeds the cost. That number of transactions is quite sensitive to the discharge cost, so a modest increase may reduce the number of viable transactions considerably.

Two performance characteristics that have a significant impact on storage variable operating cost are efficiency and the rate at which storage performance declines as it is used.

3.2.1.3. Application Synergies

Although each case is unique, if a plant used for electric energy time-shift is in the right location and if it is discharged at the right times, it could also serve the following applications: electric supply capacity, T&D upgrade deferral, transmission congestion relief, electric service reliability, electric service power quality, and ancillary services.

3.2.2. Application #2 — Electric Supply Capacity

3.2.2.1. Application Overview

Depending on the circumstances in a given electric supply system, energy storage could be used to defer and/or to reduce the need to buy new central station generation capacity and/or to 'rent' generation capacity in the wholesale electricity marketplace.

In many areas of the U.S., the most likely type of new generation plant 'on the margin' is a natural gas-fired combined cycle power plant. For utilities needing additional *peaking* capacity, the conventional proxy or default alternative is usually a relatively clean, simple cycle combustion turbine. Depending on circumstances, however, other peaking resources may be preferred (*e.g.*, other types of central/bulk generation, distributed generation, demand response, and energy efficiency).

The marketplace for electric supply capacity is evolving. In some cases, to one extent or another, generation capacity cost is included in wholesale *energy* prices (as an allocated cost per unit of energy). In other cases, market mechanisms may allow for capacity-related payments. In fact, the price paid for capacity *not* used – under terms of utility demand response programs – may reflect some or all of the marginal cost for generation capacity.

3.2.2.2. Technical Considerations

The operating profile for storage used as supply capacity (characterized by annual hours of operation, frequency of operation, and duration of operation for each use) is circumstance-specific. Consequently, it is challenging to make generalizations about storage discharge duration for this application. Another key criterion affecting discharge duration for this application is the way that generation capacity is priced. For example, if capacity is priced per hour, then storage plant duration is flexible. If prices require that the capacity resource be available for a specified duration for each occurrence (*e.g.*, five hours), or require operation during an entire time period (*e.g.,* 12:00 p.m. to 5:00 p.m.), then the storage plant discharge duration must accommodate those requirements.

3.2.2.3. Application Synergies

Depending on location and other circumstances, storage used for this application may be compatible with the following applications: electric energy time-shift, electric supply reserve capacity, area regulation, voltage support, T&D upgrade deferral, transmission support and congestion relief, electric service power quality, and electric service reliability.

3.3. *Ancillary Services Applications*

3.3.1. Application #3 — Load Following

3.3.1.1. *Application Overview*

Load following is one of the ancillary services required to operate the electricity grid. (See Appendix A for more detail about ancillary services.) Load following capacity is characterized by power output that changes as frequently as every several minutes. The output changes in response to the changing balance between electric supply (primarily generation) and end user demand (load) within a specific region or area. Output variation is a "…response to changes in system frequency, timeline loading, or the relation of these to each other…" that occurs as needed to "…maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits."[9]

Conventional generation-based load following resources' output *increases* to follow demand *up* as system load increases. Conversely, load following resources' output *decreases* to follow demand *down* as system load decreases. Typically, the amount of load following needed in the up direction (load following up) increases each day as load increases during the morning. In the evening, the amount of load following needed in the down direction (load following down) increases as aggregate load on the grid drops. A simple depiction of load following is shown in Figure 3.

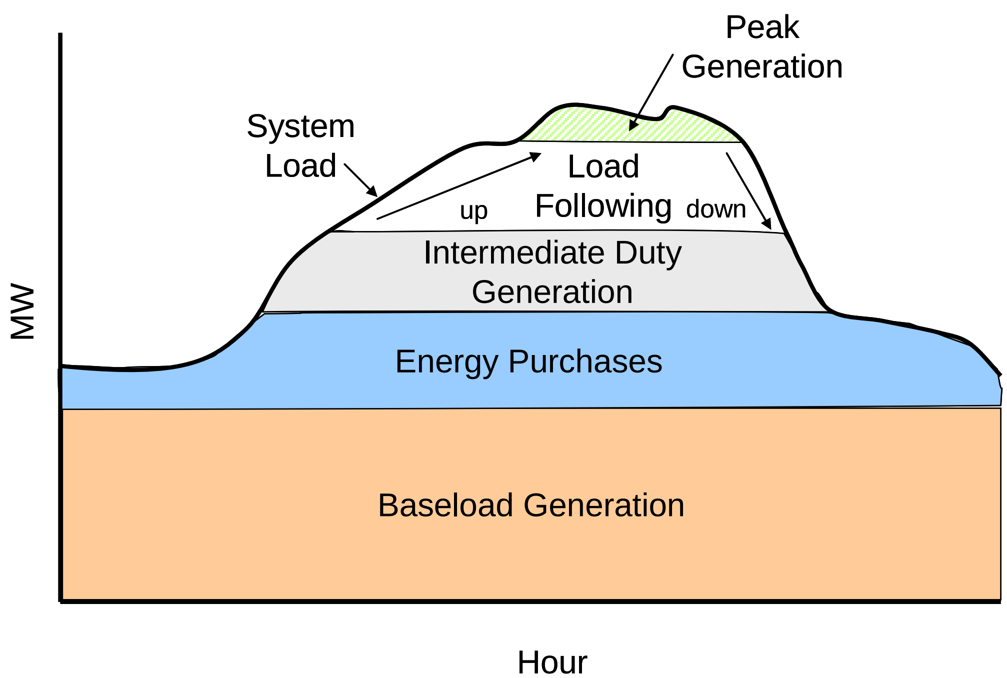


Figure 3. Electric supply resource stack.

Normally, generation is used for load following. For *load following up*, generation is operated such that its output is less than its design or rated output (also referred to as 'part load operation'). That allows operators to increase the generator's output, as needed, to provide load following up to accommodate increasing load. For *load following down*, generation starts at a high output level, perhaps even at design output, and the output is decreased as load decreases.

These operating scenarios are notable because operating generation at part load requires more fuel and results in increased air emissions relative to generation operated at its design output level. Also, varying the output of generators (rather than operating at constant output) may increase fuel use and air emissions, and it increases the need for generator variable maintenance.

Storage is well-suited to load following for several reasons. First, most types of storage can operate at partial output levels with relatively modest performance penalties. Second, most types of storage can respond very quickly (compared to most types of generation) when more or less output is needed for load following. Consider also that storage can be used effectively for both load following up (as load increases) and for load following down (as load decreases), either by discharging or by charging. (See Appendix D for details.)

When *charging* storage for load following, the energy stored must be purchased at the prevailing wholesale price. This is an important consideration – especially for storage with lower efficiency and/or if the energy used for charging is relatively expensive – because the cost of energy used to charge storage (to provide load following) may exceed the value of the load following service.

Conversely, the value of energy *discharged* from storage to provide load following is determined by the prevailing price for wholesale energy. Depending on circumstances (*i.e.*, if the price for the load following service does not include the value of the wholesale energy involved), when discharging for load following, two benefits accrue – one for the load following service and another for the energy.

Storage competes with central and aggregated distributed generation and with aggregated demand response/load management resources including curtailable/interruptible loads and direct load control.

3.3.1.2. Technical Considerations

Storage used for load following should be somewhat-to-very reliable or it cannot be used to meet contractual obligations associated with bidding in the load following market. Storage used for load following will probably need access to automated generation control (AGC) from the respective independent system operator (ISO). Typically, an ISO requires output from an AGC resource to change every minute.

For this application, storage could provide up to two service hours per hour of discharge duration. (See Appendix D for details.)

3.3.1.3. Application Synergies

Large/central storage used for load following may be especially complementary to other applications if charging and discharging for the other applications can be coordinated with charging and discharging to provide load following. For example, storage used to provide generation capacity mid-day could be charged in the evening thus following diminished system demand down during evening hours.

Load following could have good synergies with renewables capacity firming, electric energy time-shift, and possibly electric supply reserve capacity applications. If storage is distributed, then that same storage could also be used for most of the distributed applications and for voltage support.

3.3.2. Application #4 — Area Regulation

3.3.2.1. Application Overview

Area regulation (regulation) is one of the ancillary services for which storage may be especially well-suited. Regulation involves managing "interchange flows with other control areas to match closely the scheduled interchange flows" and moment to moment variations in demand within the control area.[10]

The primary reasons for including regulation in the power system are to maintain the grid frequency and to comply with the North American Electric Reliability Council's (NERC's) Control Performance Standards 1 and 2 (NERC 1999a). Regulation also assists in recovery from disturbances, as measured by compliance with NERC's Disturbance Control Standard.[11]

In more basic terms, regulation is used to reconcile momentary differences between supply and demand. That is, at any given moment, the amount of electric supply capacity that is operating may exceed or may be less than load. Regulation is used for damping of that difference. Consider the example shown in Figure 4. In that figure, the thin (red) plot with numerous fluctuations depicts total system demand without regulation. The thicker (black) plot shows system load after damping of the short-duration fluctuations with regulation.

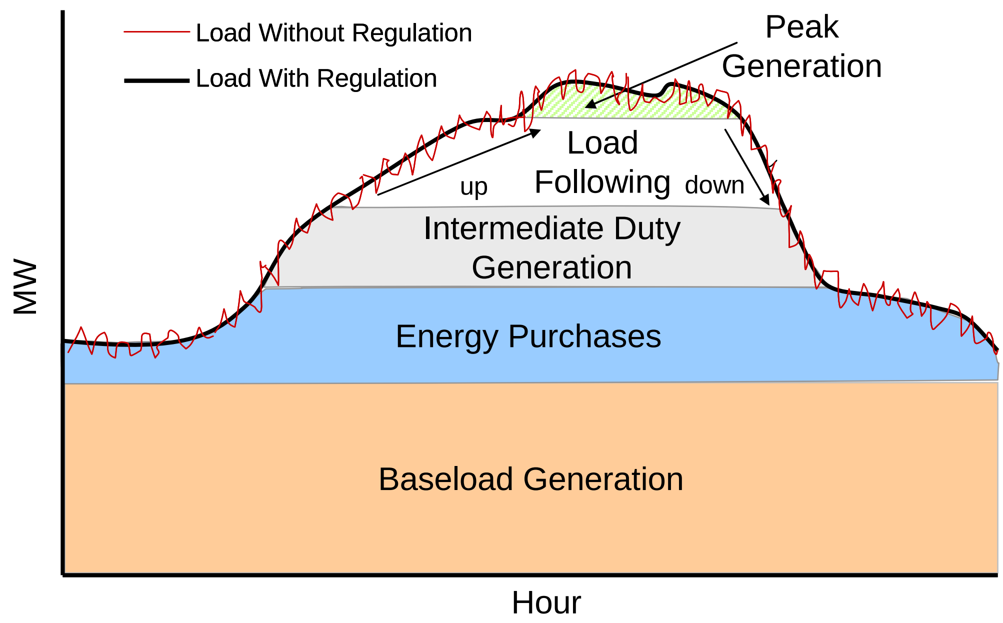


Figure 4. System load without and with area regulation.

Regulation is typically provided by generating units that are online and ready to increase or decrease power as needed. When there is a momentary shortfall of electric supply capacity, output from regulation resources is increased to provide *up regulation*. Conversely, regulation resources' output is reduced to provide *down regulation* when there is a momentary excess of electric supply capacity.

An important consideration for this application is that most thermal/baseload generation used for regulation service is not especially well-suited or designed to provide regulation. This is because most types of thermal/baseload generation are not designed for operation at part load or to provide variable output. Notably, thermal power plant fuel conversion is usually most efficient when power plants operate at a specific and constant (power) output level. Similarly, air emissions and plant wear and tear are usually lowest (per kWh of output) when thermal generation operates at full load and with constant output.

So, storage may be an attractive alternative to most generation-based load following for at least three reasons: 1) in general, storage has superior part-load efficiency, 2) *efficient* storage can be used to provide up to two times its rated capacity (for regulation), and 3) storage output can be varied rapidly (*e.g.*, output can change from none to full or from full to none within seconds rather than minutes).

Two possible operational modes for 1 MW of *storage* used for regulation and three possible operational modes for *generatio*n used for regulation are shown in Figure 5. The leftmost plot shows how less-efficient storage could be used for regulation. In that case, increased storage discharge is used to provide up regulation and reduced discharge is used to provide down regulation. In essence, one half of the storage's capacity is used for up regulation and the other half of the storage capacity is used for down regulation (similar to the rightmost plot which shows how 1 MW of *generation* is often used for regulation service). Next, consider the second plot which shows how 1 MW of *efficient* storage can be used to provide 2 MW of regulation – 1 MW up and 1 MW down – using discharging and charging, respectively.

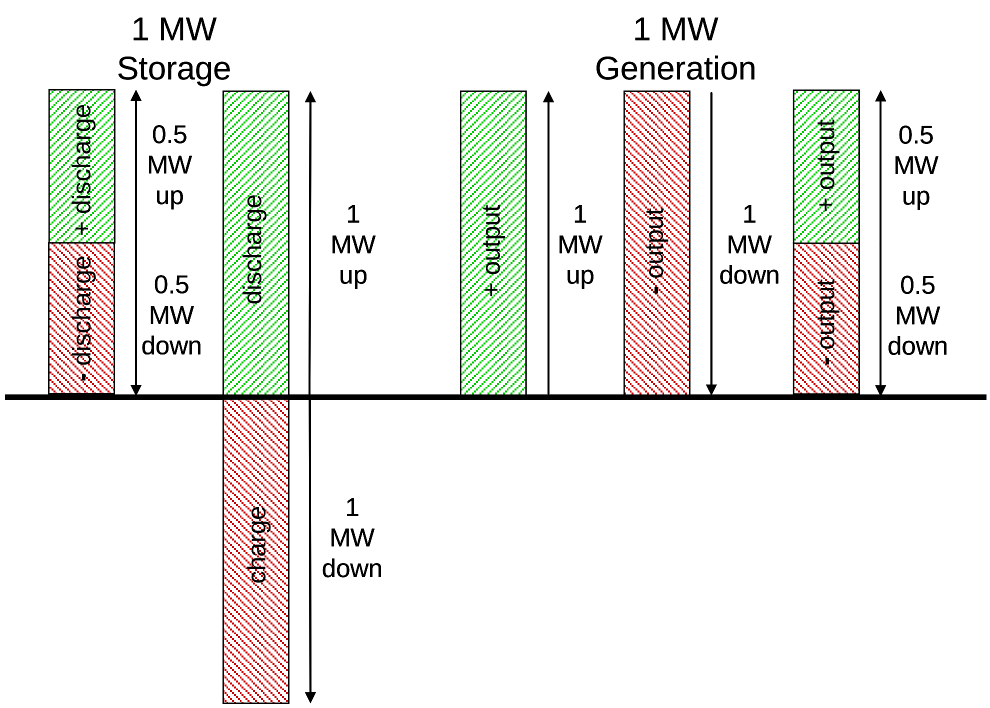


Figure 5. Storage and generation operation for area regulation.

When storage provides down regulation by charging, it *absorbs* energy from the grid, and the storage operator must pay for that energy. That is notable – especially for storage with lower efficiency – because the cost for that energy may exceed the value of the load following service. (Energy stored during load following, however, could be used later for other benefits which, if combined with the load following benefit, may still be attractive.)

3.3.2.2. Technical Considerations

The rapid-response characteristic (*i.e.*, fast ramp rate) of some types of storage makes that storage especially valuable as a regulation resource. In fact, the benefit of regulation from storage with a fast ramp rate (*e.g.*, flywheels, capacitors, and some battery types) is on the order of two times that of regulation provided by generation. (See Appendix E for details.)

Storage used for regulation should have access to and be able to respond to the area control error (ACE) signal which may require a response time of less than five seconds. Resources used to provide regulation should be quite reliable, and they must have high quality, stable (power) output characteristics.

3.3.2.3. Application Synergies

In most cases, storage used to provide area regulation cannot be used *simultaneously* for another application. However, at any given time, storage *could* be used for another more beneficial application *instead* of using it for regulation (*e.g.*, electric energy time-shift, electric supply capacity, electric supply reserve capacity, or T&D upgrade deferral).

3.3.3. Application #5 — Electric Supply Reserve Capacity

3.3.3.1. Application Overview

Prudent operation of an electric grid includes use of electric supply reserve capacity (reserve capacity) that can be called upon when some portion of the normal electric supply resources become unavailable unexpectedly. In the electric utility realm, this reserve capacity is classified as an ancillary service. (See Appendix A and [12] for details about ancillary services.)

At minimum, reserves should be at least as large as the single largest resource (*e.g.*, the single largest generation unit) serving the system. Generally, reserve capacity is equivalent to 15% to 20% of the normal electric supply capacity, although specific reserve margins are designated in rules and/or regulations. In the U.S., the National Electric Reliability Council (NERC) is a key agency involved in establishing reserve capacity requirements.[13]

The three generic types of reserve capacity are:

- **Spinning Reserve –** Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency-responsive' spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when a shortfall occurs.
- **Supplemental Reserve –** Generation capacity that may be offline, or that comprises a block of curtailable and/or interruptible loads, and that can be available within 10 minutes. Unlike spinning reserve capacity, supplemental reserve capacity is not synchronized with the grid (frequency). Supplemental reserves are used after all spinning reserves are online.

- **Backup Supply** – Generation that can pick up load within one hour. Its role is, essentially, a backup for spinning and supplemental reserves. Backup supply may also be used as backup for commercial energy sales.

Importantly for storage, *generation* resources used as reserve capacity must be online and operational (*i.e.*, at part load). Unlike generation, in almost all circumstances, *storage* used for reserve capacity does not discharge at all – it just has to be ready and available to discharge *if needed*.

Note that storage can provide two times its capacity as reserve capacity when the storage is charging, because the storage can simultaneously stop charging *and* start discharging.

3.3.3.2. Technical Considerations

Of course, storage used for reserve capacity must have enough stored energy to discharge for the required amount of time (usually at least one hour).

Storage used for this application must be somewhat reliable, though penalties for not providing the service after a bid are not onerous for individual events. Reserve capacity resources must receive and respond to appropriate control signals. Typical discharge durations for this application are between one and two hours. Reserve capacity may have to respond to the ISO's AGC signal.

3.3.3.3. Application Synergies

Electric supply reserve capacity is especially compatible with other applications and application combinations primarily for the following reasons:

- Most times when storage is used for reserves, it does not discharge.
- While charging, storage can provide two times its capacity as reserve capacity.
- If there is an hour-ahead market for reserve capacity, then decisions can be made almost real-time regarding the merits of discharging – if needed – compared to saving the energy to use later, for more benefit.[14]

In most cases, storage cannot serve any other applications while it is providing electric supply reserve capacity. Nevertheless, when storage is not used as electric supply reserve capacity, it could be used for electric energy time-shift, electric supply capacity, other ancillary services, renewables energy time-shift, renewables capacity firming, and wind generation grid integration. Depending on location, it could also be used for transmission congestion relief and T&D upgrade deferral.

3.3.4. Application #6 — Voltage Support

3.3.4.1. Application Overview

An important technical challenge for electric grid system operators is to maintain necessary voltage levels with the required stability. In most cases, meeting that challenge requires management of a phenomenon called 'reactance'. Reactance occurs because equipment that generates, transmits, or uses electricity often has or exhibits characteristics like those of inductors and capacitors in an electric circuit. (See Appendix C for more details.)

To manage reactance at the grid system level, grid system operators rely on an ancillary service called ‘voltage support’. The purpose of voltage support is to offset reactive effects so that grid system voltage can be restored or maintained.

Historically, voltage support has been provided by generation resources. Those resources are used to generate reactive power (VAR) that offsets reactance in the grid. New technologies (*e.g.,* modular energy storage, modular generation, power electronics, and communications and control systems) make new alternatives for voltage support increasingly viable.[15][16]

(Conventional ‘power factor correction’ capacitors are good for managing *localized* reactance that occurs *during normal operating conditions*. Capacitors do not perform well as a voltage support resource, however, because they draw an increasing amount of current as voltage drops – to maintain power – which adds to voltage-related problems affecting the greater grid system. See Section 5.3.6 and Appendix C for more details about power factor correction.)

This is an application for which *distributed* storage may be especially attractive because reactive power cannot be transmitted efficaciously over long distances. Notably, many major power outages are at least partially attributable to problems related to transmitting reactive power to load centers. So, distributed storage – located within load centers where most reactance occurs – provides especially helpful voltage support.[17][18]

One especially notable load type for this application is smaller air conditioning (A/C) equipment like that used for residences and for small businesses. The reactance from motors used for A/C compressors poses a significant voltage-related challenge because, as grid voltage drops – during localized or region-wide grid emergencies – the motors draw an increasing amount of current to maintain power. That exacerbates the voltage problem, in part because air conditioners are most likely to be turned on when the grid is most heavily loaded and possibly when the grid is especially prone to voltage-related problems.

3.3.4.2. Technical Considerations

Storage systems used for voltage support must have VAR support capability if they will be used to inject reactive power. Also, storage used for voltage support must receive and respond quickly to appropriate control signals.

The standard value for discharge duration is assumed to be 30 minutes — time for the grid system to stabilize and, if necessary, to begin orderly load shedding.

3.3.4.3. Application Synergies

In general, storage used for voltage support must be available within a few seconds to serve load for a few minutes to perhaps as much as an hour. Thus, storage serving another application could also provide voltage support if the storage can be available within a few seconds to provide voltage support and if the storage has enough stored energy to discharge for durations ranging from a few minutes to an hour.

Central/bulk storage used for voltage support could also be used for electric energy time-shift, electric supply capacity, other ancillary services, renewables energy time-shift, renewables capacity firming, and wind generation integration.

Distributed storage used for voltage support probably cannot be used for area regulation or transmission support though it probably could be used for most or all of the other applications covered in this report with little or no *technical* conflict, though circumstance-specific dispatch needs may cause *operational* conflicts.

If the same storage is used for voltage support and for another 'must-run' application (*e.g.,* T&D upgrade deferral), then the worst case is that the storage is completely dedicated to serving local demand during the few dozen to few hundred hours per year when the T&D equipment is most heavily loaded, leaving storage available during 95%+ of the year to serve other applications.

3.4. Grid System Applications

3.4.1. Application #7 — Transmission Support

3.4.1.1. Application Overview

Energy storage used for transmission support improves T&D system performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance. The result is a more stable system with improved performance (throughput). It is similar to the ancillary service (not addressed in this guide) referred to as Network Stability. Benefits from transmission support are highly situation-specific and site-specific. Table 6 briefly describes ways that energy storage can provide transmission support.

Table 6. Types of Transmission Support

Type	Description
Transmission Stability Damping	Increase load carrying capacity by improving dynamic stability.
Sub-synchronous Resonance Damping	Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.
Voltage Control and Stability	1. Transient Voltage Dip Improvement Increase load carrying capacity by reducing the voltage dip that follows a system disturbance. 2. Dynamic Voltage Stability Improve transfer capability by improving voltage stability.
Under-frequency Load Shedding Reduction	Reduce load shedding needed to manage under-frequency conditions which occur during large system disturbances.

Source: adapted from information provided by EPRI.[19][20][21]

3.4.1.2. Technical Considerations

To be used for transmission support, energy storage must be capable of sub-second response, partial state-of-charge operation, and many charge-discharge cycles. Communication and control systems are important for this application. Also, storage used for transmission support must be very reliable. For storage to be most beneficial as a transmission support resource, it should provide both real and reactive power.[22]

Typical discharge durations for transmission support are between one and twenty seconds. The standard discharge duration assumed for this application is five seconds.

3.4.1.3. Application Synergies

Storage that is used for transmission support probably cannot be used *concurrently* for other applications. Nevertheless, storage used for transmission support during peak demand or peak congestion times could be used at other times for several other applications, if the storage has the necessary discharge duration (*e.g.*, one hour or more for ancillary services).

3.4.2. Application #8 — Transmission Congestion Relief

3.4.2.1. Application Overview

In many areas, transmission capacity additions are not keeping pace with the growth in peak electric demand. Consequently, transmission systems are becoming congested during periods of peak demand, driving the need and cost for more transmission capacity and increased transmission access charges. Additionally, transmission congestion may lead to increased use of congestion charges or locational marginal pricing (LMP) for electric energy.

Storage could be used to avoid congestion-related costs and charges, especially if the charges become onerous due to significant transmission system congestion. In this application, storage systems would be installed at locations that are electrically downstream from the congested portion of the transmission system. Energy would be stored when there is no transmission congestion, and it would be discharged (during peak demand periods) to reduce transmission capacity requirements.

3.4.2.2. Technical Considerations

The discharge duration needed for transmission congestion relief cannot be generalized easily, given all the possible manifestations. As with the T&D upgrade deferral application, it may be that there are just a few individual hours throughout the year when congestion charges apply. Or, there may be a few occurrences during a year when there are several consecutive hours of transmission congestion. Also, congestion charges may be applied like demand charges with payments made for maximum demand during specific times during specific months of the year. Congestion charges may vary from year to year because supply and demand are always changing.

The standard discharge duration assumed for this application is four hours.

3.4.2.3. Application Synergies

Depending on location, the owner, the discharge duration, and other circumstances, storage used for transmission congestion relief may be compatible with most if not all applications described in this report, especially electric energy time-shift, electric supply capacity (peaking), ancillary services, and possibly renewable energy time-shift.

3.4.3. Application #9 — Transmission and Distribution Upgrade Deferral

3.4.3.1. Application Overview

Transmission and distribution (T&D) upgrade deferral involves delaying – and in some cases avoiding entirely – utility investments in transmission and/or distribution system upgrades, using relatively small amounts of storage. Consider a T&D system whose peak electric loading is approaching the system's load carrying capacity (design rating). In some cases, installing a small amount of energy storage downstream from the nearly overloaded T&D node will defer the need for a T&D upgrade.

Consider a more specific example: A 15-MW substation is operating at 3% below its rating and load growth is about 2% per year. In response, engineers plan to upgrade the substation next year by adding 5 MVA of additional capacity. As an alternative, engineers could consider installing enough storage to meet the expected load growth for next year, plus any appropriate engineering contingencies (*i.e.*, it may not be prudent to install 'just enough' storage, especially if there is uncertainty about load growth). For the 15-MW substation in this example: At a 2% load growth rate, the load growth during the next year will be 300 kW (2% × 15 MW). Adding a 25% engineering contingency, the storage plant needed to defer T&D upgrade would be about 375 kW.

The key theme is that a *small* amount of storage can be used provide enough *incremental* capacity to defer the need for a *large* 'lump' investment in T&D equipment. Doing so reduces overall cost to ratepayers; improves utility asset utilization; allows use of the capital for other projects; and reduces the financial risk associated with lump investments.

Notably, for most nodes within a T&D system, the highest loads occur on just a few days per year, for just a few hours per year. Often, the highest annual load occurs on one specific day whose peak is somewhat higher than any other day. One important implication is that storage used for this application can provide a lot of benefit with limited or no need to discharge. Given that most modular storage types have a high variable operating cost, this application may be especially attractive for some storage types.

Alhough the emphasis for this application is on T&D *upgrade deferral*, a similar rationale applies to T&D equipment *life extension*. That is, if storage use reduces loading on existing equipment that is nearing its expected life, the result could be to extend the life of the existing equipment. This may be especially compelling for T&D equipment that includes aging transformers and underground power cables.

Readers are encouraged to see the Sandia National Laboratories report entitled *Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage* for more details.[23]

3.4.3.2. Technical Considerations

Energy storage must serve sufficient load, for as long as needed, to keep loading on the T&D equipment below a specified maximum. Discharge duration is a critical design criterion that cannot be generalized well. It may require interaction with utility engineers or engineers that design and/or operate distribution systems. The standard discharge duration is assumed to range from three to six hours.

3.4.3.3. Application Synergies

Utility-owned storage used for T&D deferral is also likely to be well-suited for several other applications, especially electric energy time-shift, electric supply capacity (peaking), and electric supply reserve capacity. Depending on location and circumstances, the same utility-owned storage could also be used for voltage support, transmission congestion relief, electric service reliability, electric service power quality, and renewables energy time-shift.

If the storage is customer-owned, it may be especially compatible with TOU energy cost and demand charge management as well as electric service reliability and electric service power quality and for renewables (co-located distributed PV) capacity firming.

3.4.4. Application #10 — Substation On-site Power

3.4.4.1. Application Overview

There are at least 100,000 battery storage systems at utility substations in the U.S. They provide power to switching components and to substation communication and control equipment when the grid is not energized. The vast majority of these systems use lead-acid batteries, mostly vented and to a lesser extent valve-regulated, with 5% of systems being powered by NiCad batteries.[24]

Apparently, users are generally satisfied, though reduced need for routine maintenance, improved reliability, and longer battery life would make alternatives attractive, especially if the cost is comparable to that of the incumbent technologies.

3.4.4.2. Technical Considerations

One important feature that competitive substation on-site power options must have is equal or better reliability than the standard option. Ideally, new options have lower maintenance requirements than the existing systems. Also, competitive options should have a straightforward way to determine the storage system’s remaining useful life and ideally its ‘state-of-health’.

One feature needed to address an emerging opportunity is the ability to serve the growing number of on-site DC loads (*e.g.,* from DC motors and actuators replacing electro-mechanical systems). Especially important are the capacity to provide inrush currents (*e.g.,* for motor startup) and a faster ramp rate to serve momentary loads including switchgear operation, motor-driven valves, isolating switches, and the field flashing of generators.[25]

IEEE Standard 485, which addresses sizing of battery systems for substation DC loads, groups substation DC loads into three categories: 1) continuous loads, 2) non-continuous loads, and 3) momentary loads. Based on results from a survey of systems, locations serving voltages of about 69 kV are rated at 1.6 kVA; locations serving the grid at 69 kV to 169 kV have storage rated at about 2.9 kVA; and substations serving the grid at voltages exceeding 169 kV have storage systems rated at 8.5 kVA. The standard value assumed is 2.5 kW. The standard discharge duration is assumed to range from 8 to 16 hours.

3.4.4.3. Application Synergies

Conceptually, the same storage used for substation on-site power could be used for other applications. Key considerations include a) use of the storage for other applications cannot degrade reliability and b) the storage must have sufficient discharge duration to serve the substation on-site power application *plus* other applications (*i.e.*, enough energy must be stored to serve the substation on-site power application *and* the other applications). For example, if 8 hours of discharge duration is required for substation on-site power and 5 hours are required for another application then the total discharge duration must be 8 + 5 = 13 hours. Given the high incremental cost for most types of storage that would be used for substation on-site power, use of the same storage system for other applications may be impractical in most circumstances.

3.5. End User/Utility Customer Applications

3.5.1. Application #11 — Time-of-use Energy Cost Management

3.5.1.1. Application Overview

Time-of-use (TOU) energy cost management involves storage used by energy end users (utility customers) to reduce their overall costs for electricity. Customers charge the storage during off-peak time periods when the electric energy price is low, then discharge the energy during times when on-peak TOU energy prices apply. This application is similar to electric energy time-shift, although electric energy prices are based on the customer's *retail* tariff, whereas at any given time the price for electric energy time-shift is the prevailing *wholesale* price.

Pacific Gas and Electric Company's (PG&E's) Small Commercial TOU A-6 tariff was used for the working example. It applies from May to October, Monday through Friday. Commercial and industrial electricity end users whose peak power requirements are less than or equal to 500 kW are eligible for the A-6 tariff.

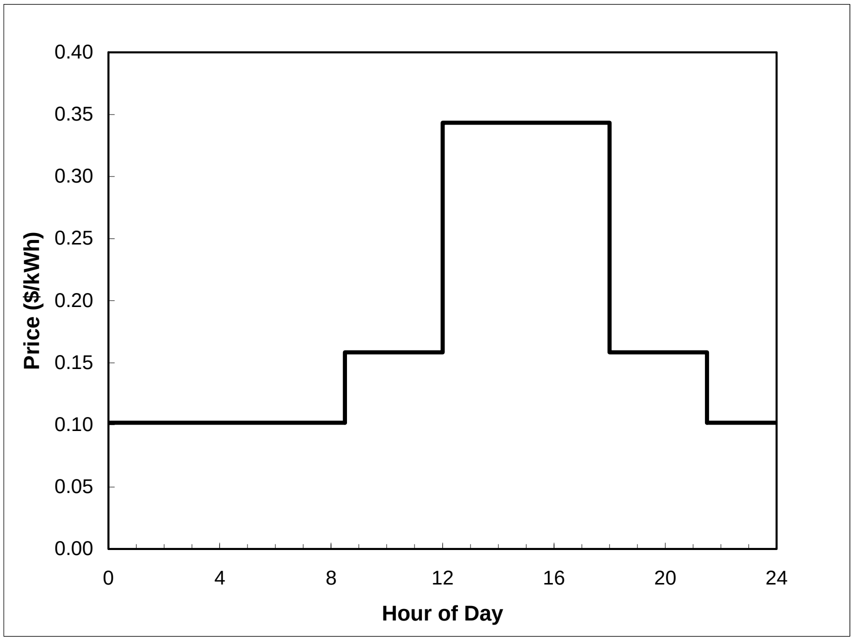


Figure 6. Summer energy prices for PG&E's Small Commercial A-6 TOU rate.

As shown in Figure 6, energy prices are about 32 ¢/kWh on-peak (12:00 p.m. to 6:00 p.m.). Prices during partial-peak (8:30 a.m. to 12:00 p.m. and 6:00 p.m. to 9:30 p.m.) are about 15 ¢/kWh, and during off-peak (9:30 p.m. to 8:30 a.m.) prices are about 10 ¢/kWh.

Although electricity end users receive the benefit for reducing energy cost, it is likely that that storage design, procurement, transaction costs, *etc.* would be too challenging for many potential users, especially those with relatively small energy use. If so, one option is to establish a partnership with an aggregator, as discussed in Section 6.5.4.

3.5.1.2. Technical Considerations

The maximum discharge duration for this application is determined based on the relevant tariff. For example, for the A-6 tariff there are six on-peak hours (12:00 p.m. to 6:00 p.m.). The standard value assumed for this application is five hours of discharge duration.

3.5.1.3. Application Synergies

Depending on overlaps between on-peak energy prices and times when peak demand charges apply, the same storage system use for time-of-use energy cost management might also be compatible with the demand charge management application. It could also provide benefits associated with improved electric service power quality and improved electric service reliability. Similarly, depending on a plant's discharge duration and when discharge occurs, it may be compatible with the T&D upgrade deferral application.

3.5.2. Application #12 — Demand Charge Management

3.5.2.1. Application Overview

Energy storage could be used by electricity end users (*i.e.,* utility customers) to reduce the overall costs for electric service by reducing demand charges, by reducing power draw during specified periods, normally the utility's peak demand periods.

To avoid a demand charge, load[*] must be reduced during all hours of the demand charge period, usually a specified period of time (*e.g.,* 11:00 a.m. to 5:00 p.m.) and on specified days (most often weekdays). In many cases, the demand charge is assessed if load is present during just one 15-minute period, during times of the day and during months when demand charges apply.

The most significant demand charges assessed are those based on the maximum load during the peak demand period (*e.g.,* 12:00 p.m. to 5:00 p.m.) in the respective month. It is somewhat common to also assess additional demand charges for 1) part peak or (partial peak) demand that occurs during times such as 'shoulder hours' in the mornings and evenings and during winter weekdays and 2) 'baseload' or 'facility' demand charges that are based on the peak demand no matter what time (day and month) it occurs. The latter is important for storage because facility demand charges apply at any time, including at night when most storage charging occurs.

Because there is a facility demand charge assessed during charging, the amount paid for *facility* demand charges offsets some of the benefit for reducing demand during times when the higher

[*] In the utility realm, 'demand' often refers to the maximum *power* draw during a specified period of time (*e.g.,* a month or year). To avoid confusion relative to the more general economics definition, especially regarding demand for energy, in this report 'load' is often used instead of the term demand when referring to *power* draw.

peak demand charges apply. Consider a simple example: The peak demand charge (which applies during summer afternoons, from 12:00 p.m. to 5:00 p.m.) is $10/kW-month, and the annual facility demand charge is $2/kW-month. During the night, when charging occurs, the $2/kW facility demand charge is incurred; when storage discharges mid-day (when peak demand charges apply), the $10/kW-month demand charge is avoided. The *net* demand charge reduction in the example is

$10/kW-month – $2/kW-month = $8/kW-month.

Note that the price for electric *energy* is expressed in $/kWh used, whereas demand charges are denominated in $/kW of maximum *power* draw. Tariffs with demand charges have separate prices for energy and for power (demand charges). Furthermore, demand charges are typically assessed for a given month, thus demand charges are often expressed using $/kW per month ($/kW-month).

To reduce load when demand charges are high, storage is charged when there are no or low demand charges. (Presumably, the price for charging energy is low too.) The stored energy is discharged to serve load during times when demand charges apply. Typically, energy storage must discharge for five to six hours for this application, depending on the provisions of the applicable tariff.

Consider the example illustrated in Figure 7. The figure shows a manufacturer’s load that is nearly constant at 1 MW for three shifts. During mornings and evenings, the end user’s direct load and the facilities’ net demand are 1 MW. At night, when the price for energy is low, the facility’s net demand doubles as low-priced energy is stored at a rate of 1 MW while the normal load from the end user’s operations requires another MW of power. During peak demand times (12:00 p.m. to 5:00 pm in the example), storage discharges (at the rate of 1 MW) to serve the end user’s direct load of 1 MW, thus eliminating the real-time demand on the grid.

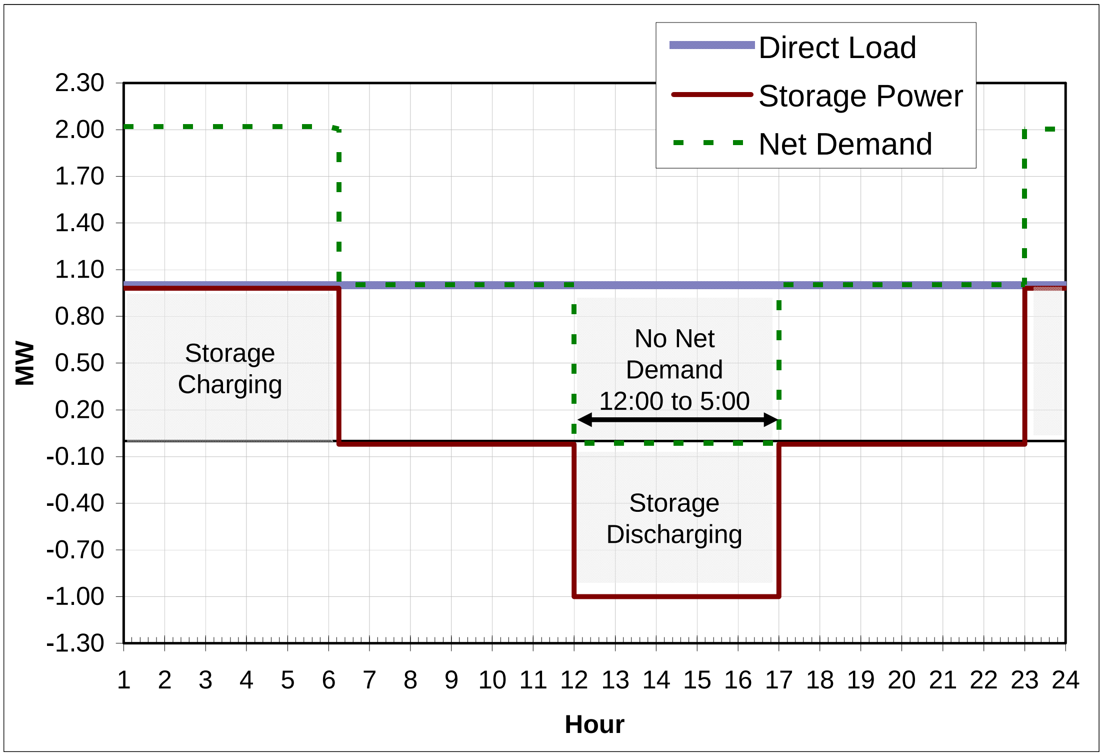


Figure 7. On-peak demand reduction using energy storage.

In the above example, storage is 80% efficient. To discharge for 5 hours, it must be charged for

5 hours ÷ 0.8 = 6.25 hours.

The 'additional' 1.25 hours of charging is needed to offset energy losses. If a facility demand charge applies, it would be assessed on the entire 2 MW (of net demand) used to serve both load and storage charging.

Although it is the electricity customer that internalizes the benefit, for this application, the author presumes that the design, procurement, transaction cost, *etc.* could be challenging for many prospective users, especially those with relatively small peak loads. One possible way for storage to be viable for those prospective users is to partner with an aggregator.

3.5.2.2. Technical Considerations

Given that demand charges apply for an entire month (and perhaps even for an entire year), for maximum load that occurs for even a few minutes, storage must be reliable. It must have acceptable or better power quality for loads served.

For this application, the storage plant discharge duration is based on the applicable tariff. For example, PG&E's E-19 Medium General Demand-Metered TOU tariff defines six on-peak hours (12:00 p.m. to 6:00 p.m.). The standard assumption for this application is five hours of discharge duration.

3.5.2.3. Application Synergies

Although each circumstance is different, storage used for demand charge management may be compatible with the electric energy time-shift application, and it could provide some ancillary services if end users are allowed to participate in the wholesale energy marketplace.

This application may be compatible with the transmission congestion relief and T&D upgrade deferral applications if storage use reduces load on T&D equipment when and where needed. (Note that T&D owners must be motivated and allowed to share related benefits, either by contract or prices.) Storage used for demand charge management is also likely to be compatible with the TOU energy cost management application if storage is discharging during times when energy price is high. Storage used for this application may also be compatible with the electric service power quality, electric service reliability, renewables capacity firming, and electric energy time-shift applications.

3.5.3. Application #13 — Electric Service Reliability

3.5.3.1. Application Overview

The electric service reliability application entails using energy storage to provide highly reliable electric service. In the event of a complete power outage lasting more than a few seconds, the storage system provides enough energy to ride through outages of extended duration; to complete an orderly shutdown of processes; and/or to transfer to on-site generation resources.

3.5.3.2. Technical Considerations

The discharge duration required is based on situation-specific criteria. If an orderly shutdown is the objective, then discharge duration may be an hour or more. If an orderly transfer to a generation device is the objective, then no more than a few minutes of discharge duration are needed. The standard value for discharge duration is 15 minutes.

Storage used for this application must reliably yield power with sufficient quality.

3.5.3.3. Application Synergies

The electric service reliability application may be compatible with most applications described in this report except area regulation and transmission support. It is especially compatible with the electric service power quality application.

If a storage system has sufficient discharge duration to serve the electric service reliability application plus other applications, it could be especially well-suited to serving the TOU energy cost and demand charge management applications as well as renewables (co-located distributed PV) capacity firming.

Depending on circumstances, the same storage system could also be used for electric energy time-shift, electric supply capacity (peaking), ancillary services, voltage support, transmission congestion relief, T&D upgrade deferral, electric service reliability, electric service power quality, and renewables energy time-shift applications.

3.5.4. Application #14 — Electric Service Power Quality

3.5.4.1. Application Overview

The electric service power quality application involves using energy storage to protect on-site loads downstream (from storage) against short-duration events that affect the quality of power delivered to the load. Some manifestations of poor power quality include the following:

- Variations in voltage magnitude (*e.g.*, short-term spikes or dips, longer term surges, or sags).
- Variations in the primary 60-Hz frequency at which power is delivered.
- Low power factor (voltage and current excessively out of phase with each other).
- Harmonics (*i.e.*, the presence of currents or voltages at frequencies other than the primary frequency).
- Interruptions in service, of any duration, ranging from a fraction of a second to several or even many minutes.

3.5.4.2. Technical Considerations

Needless to say, storage used for power quality should produce high-quality power output and should not adversely affect the grid. Typically, the discharge duration required for the power quality application ranges from a few seconds to about one minute.

3.5.4.3. Application Synergies

Given the short discharge duration and distributed deployment of storage for electric service power quality, few if any applications are compatible with storage designed specifically for that application. Nevertheless, the electric service power quality application may be compatible with several other applications if storage is designed for those other applications (*i.e.*, with longer discharge duration), especially time-of-use energy cost management, demand charge management, and electric service reliability.

3.6. Renewables Integration Applications

3.6.1. Application #15 — Renewables Energy Time-shift

3.6.1.1. Application Overview

Many renewable energy generation resources produce a significant portion of electric energy when that energy has a low financial value (*e.g.*, at night, on weekends and during holidays) – generally referred to as off-peak times. Energy storage used in conjunction with renewable energy generation could be charged using low-value energy from the renewable energy generation so that energy may be used to offset other purchases or sold when it is more valuable.

The low-value energy is generated off-peak at night and during early mornings when demand is low and supply is adequate. The energy is more valuable on-peak when demand is high and supply is tight. The energy value is especially high during hot summer afternoons when A/C use is most prevalent. The energy that is discharged from the storage could be used by the owner, sold via the wholesale or ‘spot’ market, or sold under terms of an energy purchase contract (commonly referred to as a ‘power purchase agreement’ or PPA).

Storage used for renewables energy time-shift could be located at or near the renewable energy generation site or in other parts of the grid, including at or near loads. Energy discharged from storage located at or near the renewable energy generation would have to be transported via the transmission system during on-peak times whereas storage located at or near loads is charged using low-value energy that is transmitted during off-peak times.

Typically, the storage discharge duration needed for energy time-shift ranges from four to six hours, depending mostly on the duration of the region’s off-peak and on-peak periods and the on-peak *versus* off-peak energy value or price differential.

Two variations of the renewables energy time-shift application are evaluated in this guide. They are 1) time-shift of energy from *intermittent* renewable energy generation resources and 2) time-shift of energy from *baseload* renewable energy generation resources. Intermittent renewables include solar, wind, ocean wave, tidal and, in some cases, hydroelectric. Baseload renewables – those whose output is somewhat-to-very constant, for several thousand hours per year – include geothermal, biomass, and, in some cases, hydroelectric. The *intermittent* renewable energy generation type evaluated here is wind-fueled generation. The *baseload* renewable energy generation evaluated is generic: It operates 24 hours per day and at a minimum it operates during every weekday during the year.

Storing electric energy from *solar* generation is not addressed in this report for two reasons. First, for situations involving *grid-connected* solar generation, a lot or even most electricity is produced when energy is already valuable, making energy time-shift relatively unattractive. Second, most of the value for storage used with solar generation is for capacity firming. (See Section 3.6.2.) Also not addressed is *seasonal* renewables energy time-shift. That is because storing enough energy for seasonal renewables energy time-shift is either impractical or prohibitively expensive with the possible exception of CAES.

3.6.1.2. Energy Time-shift from Wind Generation

For the case involving wind generation, low-value electric energy from wind generation is stored at night and during early mornings. The stored energy is discharged when it is most valuable — during weekday afternoons when demand for electricity is highest.

Not only does energy from wind generation produced off-peak have a low value, depending on regional circumstances wind generation occurring during off-peak hours can cause operational challenges. Two such operational challenges are minimum load violations and accommodating rapid changes to output from intermittent renewable energy generation. (See Section 3.6.3.) When minimum load violations occur, the combined output from wind generation capacity plus other ‘must-run’ generation exceeds demand (must-run generation tends to include that which is fueled by coal, nuclear, baseload renewable energy, and some types of natural-gas-fueled generation). Rapid output changes from intermittent renewable energy generation can lead to ‘ramping’ of other *dispatchable* generation, which increases wear, fuel use, and emissions (all per kWh).

An example of the daily operation profile for wind generation plus storage on a summer day is shown in Figure 8. For the scenario depicted, wind generation output occurring at night, when the energy’s value is low, is used to charge storage. In the example, about one-half of the energy used on-peak is from wind generation that occurs off-peak. The result is constant power for five hours.

For the wind generation case, storage discharge duration required ranges from two and one-half hours to as much as four hours, depending on the amount of energy from wind generation that occurs during on-peak times.

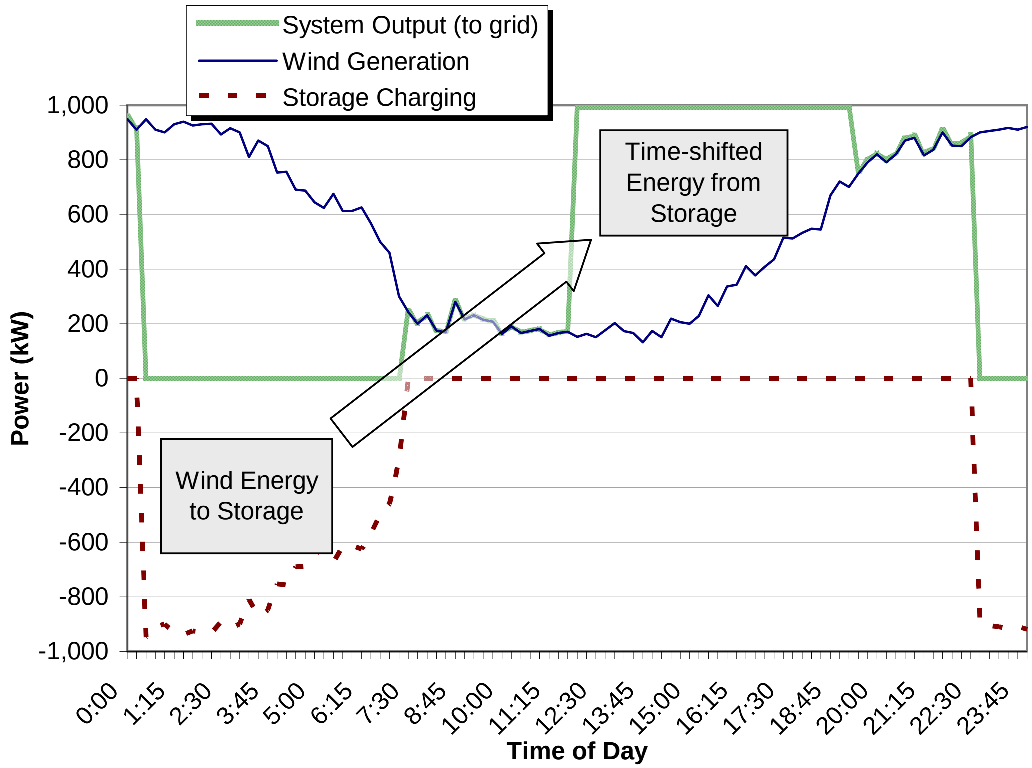


Figure 8. Wind generation energy time-shift.

3.6.1.3. Energy Time-shift from Baseload Renewable Energy Generation

Baseload renewables energy time-shift is accomplished by storing energy at night, during off-peak periods, so the energy can be used when it is most valuable, especially when hot temperatures drive significant air conditioning use.

An example of the concept is illustrated in Figure 9. The example involves storage whose power is equal to that of the generator's (1 MW) and whose discharge duration is five hours. The storage is charged during off-peak times using most or all of the generator's output and the storage discharges during five on-peak hours. Note that time-shift energy from baseload renewable energy generation has the effect of doubling the renewable energy generation's capacity during times when both demand and the value of electric supply *capacity* are highest.

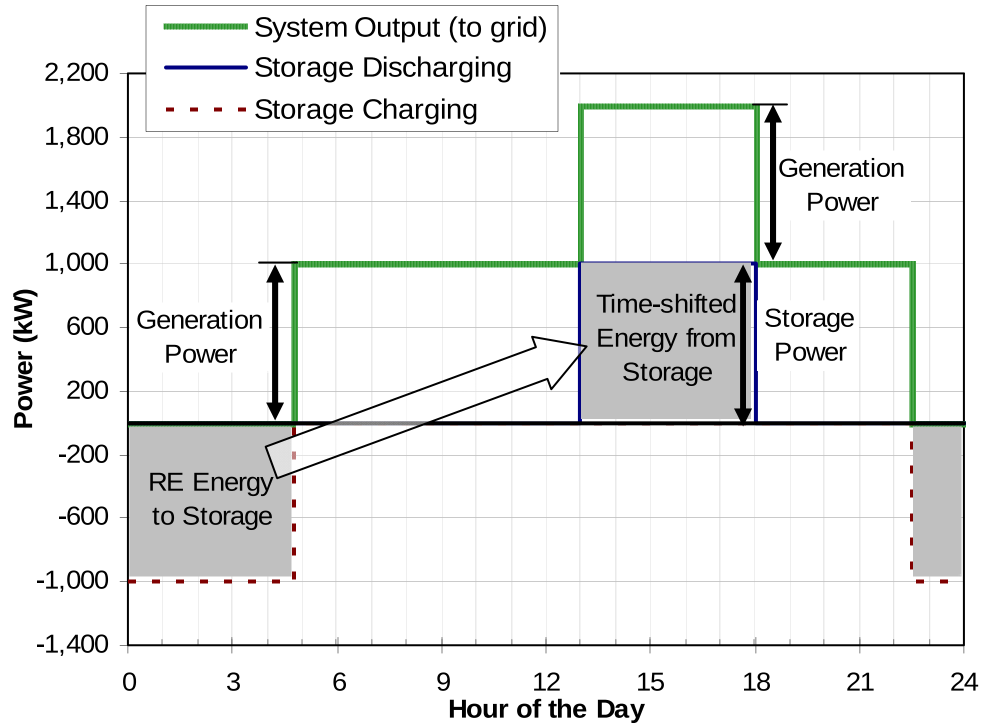


Figure 9. Baseload renewables energy time-shift.

3.6.1.4. Technical Considerations

The discharge duration for this application is circumstance-specific. It depends mostly on expectations about electric energy prices and/or the terms of the energy purchase agreement, especially the price and timing of purchases. The standard value assumed in this guide for discharge duration is five hours.

For *intermittent* renewable energy generation, another important criterion is the degree to which the renewable energy generation output coincides with times when the price for electric energy is high.

PCUs used in conjunction with many, or even most, renewable energy systems do not have what is needed to facilitate use of storage. Consequently, PCUs used for renewables energy time-shift must have additional hardware and software to accomplish and to manage charging and discharging of the storage.

3.6.1.5. Application Synergies

Depending on the location, the timing of the discharge, storage discharge duration, storage ramp rate, and the owner's flexibility to optimize storage dispatch, storage used to time-shift electric energy from renewables generation could also serve several other applications described in this report.

Renewables energy time-shift is especially compatible with the renewables capacity firming and electric supply capacity applications. Centrally located storage used for this application could also be used for electric supply reserve capacity and area regulation. If the storage is deployed in distributed mode, then the storage could serve most applications (other than area regulation), especially voltage support, transmission congestion relief, T&D upgrade deferral, electric service power quality, electric service reliability, TOU energy cost management, and demand charge management.

3.6.2. Application #16 — Renewables Capacity Firming

3.6.2.1. *Application Overview*

Renewables capacity firming applies to circumstances involving renewable energy-fueled generation whose output is intermittent. The objective is to use storage to 'fill in' so that the combined output from renewable energy generation plus storage is somewhat-to-very constant.

The resulting firmed capacity offsets the need to purchase or 'rent' additional dispatchable (capacity) electric supply resources. Depending on location, firmed renewable energy output may also offset the need for transmission and/or distribution equipment. Renewables capacity firming is especially valuable when peak demand occurs.

For the purpose of renewables capacity firming, renewable energy generation's output intermittency can be classified as 'short-duration' (*i.e.*, occurring somewhat-to-very randomly over timescales ranging from seconds to minutes) and/or 'diurnal' (*i.e.*, occurring in a regular and/or predictable way during a 24-hour period).

One important challenge associated with intermittent renewable energy generation is that the generation's power output can change rapidly over short periods of time. Photovoltaic (PV) output can drop quite quickly as clouds pass. Wind generation output can change rapidly during gusty conditions.

These rapid changes (also known as ramping) can lead to the need for dispatchable power sources whose output can also change rapidly. Most new, non-renewable energy generation facilities are best operated at constant output. In some regions, however, there may not be enough dispatchable generation capacity to offset renewable energy generation's ramping. Storage can have an important effect on the amount of dispatchable generation needed to meet the renewable energy generation ramping challenge.

> Note the important distinction between renewables *capacity firming*, and renewables *energy time-shift*.
>
> **Capacity firming** allows use of an intermittent electric supply resource as a nearly constant *power* source. Such use may reduce power-related charges (*e.g., capacity* payments or *demand* charges), or it may offset the need for *equipment* (*e.g.,* wires, transformers, and generation) which is an *investment* with a *fixed* cost.
>
> By contrast, **energy time-shift** involves enhancing the value of *energy* to increase profits and/or reduce fuel, operation, variable operation, and maintenance costs which are e*xpenses*.
>
> In most circumstances, renewables capacity firming is likely to result in a combined benefit comprised of a benefit for renewables energy time-shift and one for the firm capacity.

In broad terms, good opportunities for renewables capacity firming tend to involve renewable energy resources whose output is somewhat-to-very coincident with the peak demand and somewhat-to-very constant. Storage used to firm resources with these characteristics needs relatively modest discharge duration. Solar generation's output tends to occur when demand for electricity is highest and varies somewhat modestly, albeit predictably. In some locations, wind-fueled generation output sometimes coincides with peak load and is somewhat stable during peak load periods.

Although, in most cases, wind generation output is not as coincident with peak demand as that from solar generation, non-trivial amounts of wind generation do occur during peak demand periods. Also, wind generation tends to be ramping down as load is increasing, making firming valuable as a way to reduce load following resources. Additionally, wind generation is somewhat to quite predictable.

Given those premises, leading candidates for renewables capacity firming include those fueled with solar energy (especially PV) or with wind energy. Depending on local circumstances, ocean wave generation output could also be firmed with storage, though it is not considered in this report.

3.6.2.2. PV Capacity Firming

Although capacity firming applies somewhat equally to large ‘bulk’ solar generation facilities and to small systems, *distributed* PV systems are featured here as the solar-fueled generation because, in many circumstances, it is possible for storage to serve other valuable applications if the storage is distributed. And, distributed PV systems are more likely to have suboptimal orientation leading to output that is only somewhat coincident with peak demand periods.

The PV systems are assumed to consist of flat-panel PV modules with a fixed orientation. Fixed-orientation PV remains stationary as the sun’s position in the sky changes throughout the day. Output from fixed-orientation PV systems increases as the sun rises during the morning hours; stays somewhat constant (at the daily maximum) for one to two hours during mid-day; and declines as the sun moves across the sky in the afternoon. Consequently, output from PV with a fixed orientation is at a maximum during a portion of the peak load period in many locations. If fixed PV orientation is not optimal, it will produce a modest to significant portion of output before or after the utility’s peak demand period.

3.6.2.3. Wind Generation Firming

Large-scale ‘bulk’ wind generation is featured in this report because a significant portion of wind generation development will involve large wind farms, whereas it seems unlikely that a significant amount of *distributed* wind generation will be added, at least for the foreseeable future. Nonetheless, the capacity firming benefit could apply to distributed wind generation as well as to central/bulk wind farms.

3.6.2.4. Short-duration Intermittency

***Solar Generation Short-duration Intermittency* —** Shading caused by terrestrial obstructions such as trees and buildings can cause relatively short-duration, location-specific intermittency. The most compelling cause of short-duration intermittency from solar generation, however, is clouds. As a cloud passes over solar collectors, power output from the affected solar generation system drops. When the cloud moves away from the collector, the output returns to previous levels. Importantly, when that happens, the *rate* of change (of output from the solar generation plant) can be quite rapid. The resulting ramping increases the need for highly dispatchable and fast-responding generation such as a simple cycle combustion turbine to fill in when clouds pass over the solar collector.

Wind Generation Intermittency — Short-duration intermittency from wind generation is caused by variations of wind speed that occur throughout the day. Although such variations may not be significant during much of the year, it can be a ramping-related challenge if peak demand for electricity coincides with gusty wind conditions. Figure 10 shows a basic example of short-duration intermittency and the implications for storage needed for firming. In the figure, the one-minute average renewable energy output (for a 1-kW renewable energy plant) is plotted. Note the variation from one minute to the next.

As shown in the figure, the power needed from storage to offset the short-duration intermittency is determined based on the maximum difference between the renewable energy plant *rating* and the reduced plant *output* due to short-duration intermittency. In the example, the largest (magnitude) short-duration drop-off of power from the renewable energy generation is about 34% of the renewable energy's plant rating. Consequently, the storage plant would need to have a power rating of at least 0.34 kW per kW of renewable energy generation.

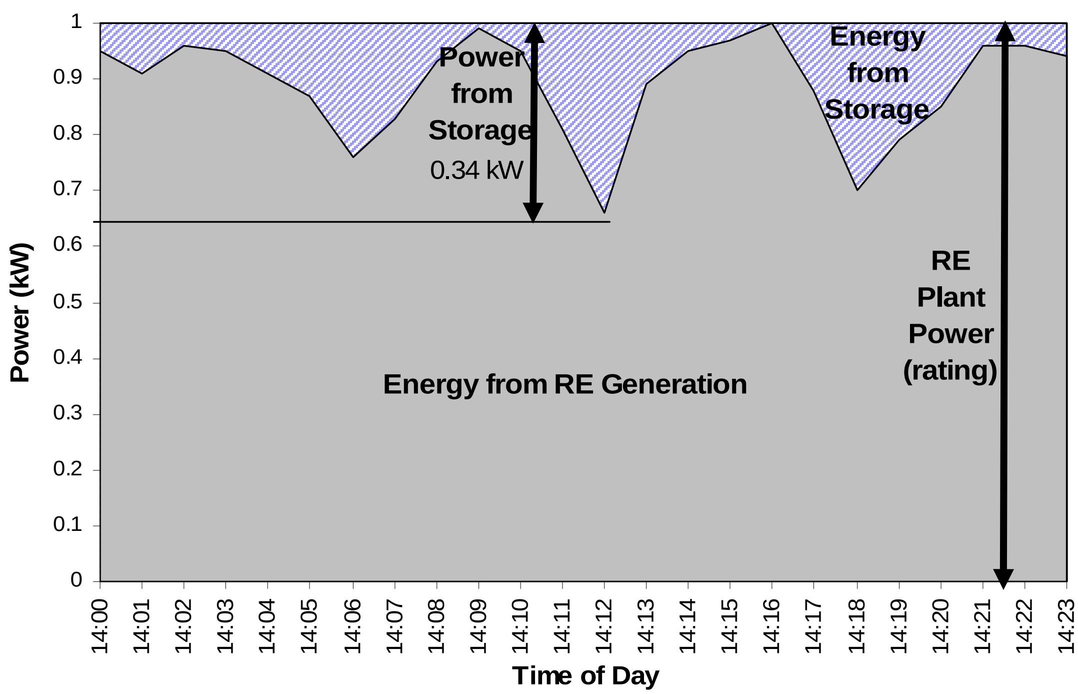


Figure 10. Renewable-fueled generation, short-duration intermittency (example).

3.6.2.5. Diurnal Intermittency

Solar Generation Diurnal Intermittency — Diurnal intermittency of solar generation is mostly related to the change of insolation throughout the day as the sun rises in the morning and then descends in the evening. Shading (not related to clouds) can also add to solar-energy-fueled generation's diurnal intermittency. Also, the solar energy-to-electricity conversion efficiency for some types of solar generation (especially flat-panel PV) drops as the equipment's temperature increases. Thus, if ambient temperatures are high, then efficiency may drop, reducing output commensurately.

The key source of diurnal intermittency from solar-energy-fueled generation is shown in Figure 11. In that example, storage is discharged when solar generation production is less than the solar plant's rated output. The figure also shows that the lowest output from the solar generation during peak demand hours (about 75% of rated capacity) occurs in the early afternoon as the sun continues to rise. The effects of short-duration intermittency, if any, are not shown. Based on the example (without regard to short-duration intermittency), firming of the PV's output requires storage whose capacity (power) is equivalent to at least 0.25 kW per kW of the solar generation's power rating. The storage must have enough *energy* to deliver 0.52 kWh per day, for each kW of the solar generation's power rating.

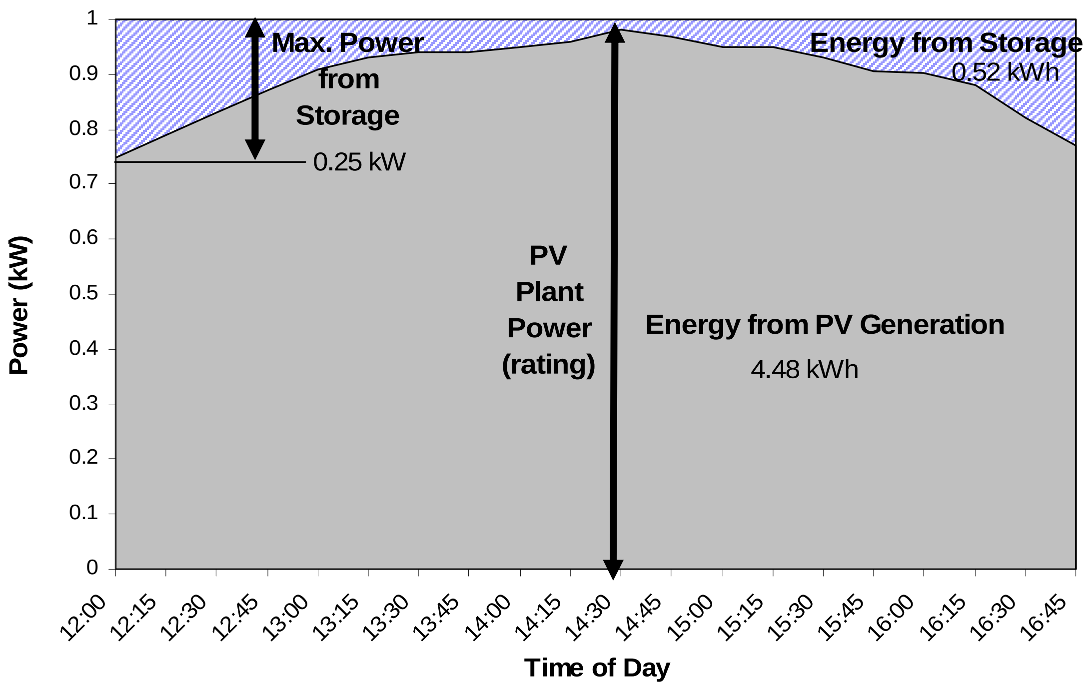


Figure 11. PV generation output variability during peak demand hours (example).

***Wind Generation Diurnal Intermittency* —** In most regions, wind tends to be stronger during certain parts of the day than during others. For example, in some regions wind speed is relatively high in the late afternoon and evening and relatively low in the morning and early afternoon. Such a scenario is shown in Figure 12. As shown in Figure 12, storage fills in when wind generation output is less than the wind turbine's rated output. In the figure, the lowest level of output from the wind generation (about 35% of rated capacity) occurs at about 1:45 p.m. (13:45). The effects of short-duration intermittency are not shown. So, for the example described in Figure 12, the storage must provide capacity (power) equal to about 65% of the wind turbine's rating. The storage must be able to deliver 2.36 kWh per kW of wind capacity for firming.

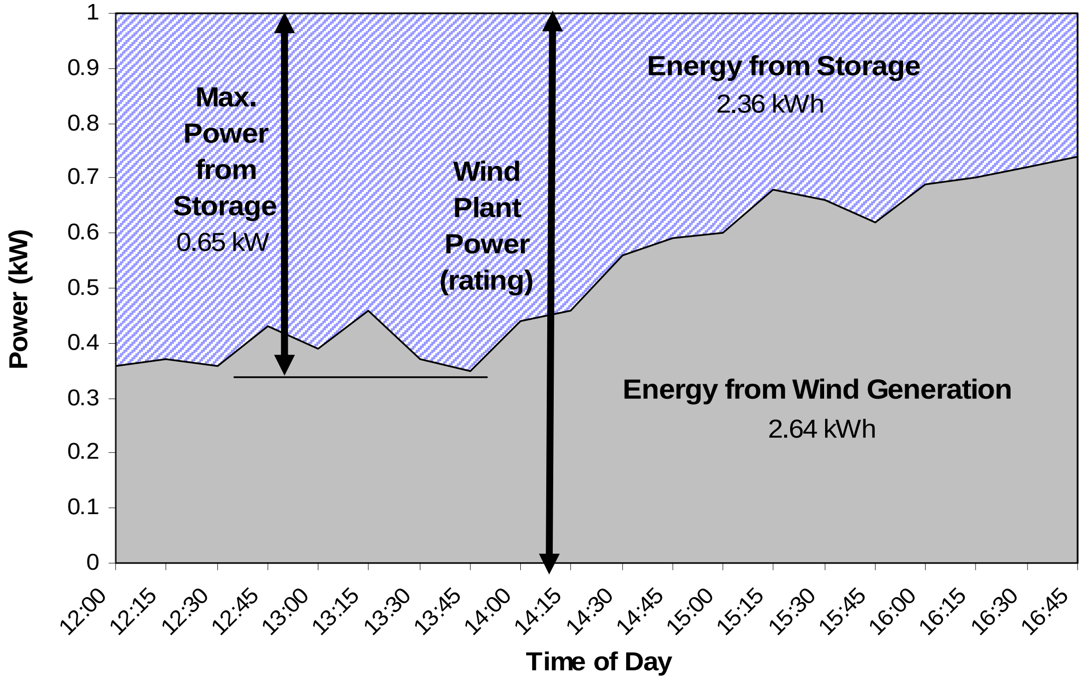


Figure 12. Wind generation diurnal intermittency during peak demand hours.

3.6.2.6. Technical Considerations

Storage power and discharge duration (for renewables capacity firming) are quite circumstance-specific and resource-specific. At the lower end, it is assumed that one-half to as much as two hours of discharge duration is needed to firm solar generation, assuming that much of PV output coincides with peak demand. For the example: To firm wind generation, a somewhat longer discharge duration (two to three hours) is needed.

Storage used for capacity firming should be quite reliable because the primary reason for capacity firming is to provide *constant power*. Also, the price paid for constant power (*i.e.*, demand charges for retail electricity end users or market price for capacity for the wholesale part of the market) is usually accompanied by a significant financial penalty if power is *not* firm.

Power conditioning equipment used for many renewable energy systems does not include the functionality needed for charging and discharging storage, which requires additional hardware and software. Nevertheless, the ability to accommodate storage can be added to the power conditioning equipment used for the renewable energy generation at a relatively low incremental cost.[26]

3.6.2.7. Application Synergies

Although possibilities are circumstance-specific, storage used for renewables capacity firming could also provide benefits related to several other applications. Renewables capacity firming is especially compatible with the renewables energy time-shift and electric supply reserve capacity applications.

For *distributed* renewable energy generation, depending on the location, capacity firming may also be compatible with several other applications including voltage support, transmission congestion relief, T&D upgrade deferral, TOU energy cost management, demand charge management, electric service reliability, and electric service power quality. Incidental benefits that could accrue are those for reduced T&D energy losses and reduced transmission access charges.

One especially attractive synergy for distributed PV plus storage is improved electric service reliability and/or improved electric service power quality. The discharge duration required for reliability-related and quality-related needs varies considerably; it depends on the robustness of the electric grid, T&D quality, and the loads and end uses served. The discharge duration needed for reliability and power quality can range from seconds to hours. For this report, it is assumed that one-quarter to one-half hour of storage (discharge duration) would be added to the PV plus storage system to provide reliability and/or power quality-related benefits.

3.6.3. Application #17 — Wind Generation Grid Integration

3.6.3.1. Application Overview

For all but modest wind generation penetration levels, wind generation is likely to have at least some undesirable impact on the grid. And wind generation *does* seem poised to be a key element of the global move toward increased use of renewable energy. In the U.S., growth of wind generation capacity will be driven, in part, by targets established under the auspices of the Renewables Portfolio Standard (RPS). (See Section 4.3.1.1 for details about RPS.)

To the extent that emphasis on renewable energy *does* increase, wind generation is well-positioned to provide a significant portion of electricity. Wind generation is especially attractive given the relatively low and dropping electricity production cost from wind generation and good or better wind resources in many geographic regions.

As wind generation penetration increases, the electricity grid effects that are unique to wind generation will also increase. Storage could assist with orderly integration of wind generation (wind integration) by managing or mitigating the more challenging and less desirable effects from high wind generation penetration.

The wind generation grid integration application includes six subtypes which are grouped into two categories: 1) short-duration (*i.e.,* lasting for a few seconds to a few minutes) and 2) long-duration (*i.e.,* lasting for many minutes to a few hours). The six subtypes are shown in Table 7.

Table 7. Wind Generation Grid Integration Categories and Subtypes

Short-duration Applications
Reduce Output Volatility
Improve Power Quality
Long-duration Applications
Reduce Output Variability
Transmission Congestion Relief
Backup for Unexpected Wind Generation Shortfall
Reduce Minimum Load Violations

3.6.3.2. Reduce Output Volatility

The reduce output volatility application subtype is related to the need to offset wind power output fluctuations caused by short-duration variation of wind generation output, lasting seconds to a few minutes.

It is important to note that, in most cases, wind turbines' geographical diversity smoothes the aggregate effect of output volatility considerably. If the wind generation is interconnected with a large, well-diversified, electric supply and grid system, then that system can accommodate significant wind generation output fluctuations.[27] Nevertheless, for large wind generation resources, even somewhat modest volatility in the aggregate output may drive a need for a non-trivial supplemental resources to supply capacity and energy. Smaller and/or less diverse wind generation resources may require even more storage capacity (per MW of wind generation capacity).

Although requirements will be different for each location and area, for this report it is assumed that a well-diversified wind generation resource using storage rated at 2% to 3% of the wind generation capacity would reduce aggregate volatility and reduce the need for area regulation significantly.[28][29] That range (2% to 3% of wind generation capacity) applies to wind penetration levels of about 10% (of total generation capacity). Presumably, the capacity needed (per kW of wind generation capacity) will change as wind generation penetration increases.

The benefit for this application is estimated based on avoided need for additional area regulation resources and service. Depending on the amount of output volatility, an alternate approach could involve that described for renewables capacity firming for short-duration intermittency as described in Section 3.6.2.4.

3.6.3.3. Improve Power Quality

The power quality application reflects a category of wind-generation-related challenges that are related to performance standards, interconnection requirements, effects from phenomena such as wind gusts, and changing electrical conditions in parts of the grid affected by and/or with an effect on wind generation operations.[30]

Seven specifically power quality-related challenges are as follows:

- Reactive power
- Harmonics
- Voltage flicker
- Transmission line protection
- Transient stability
- Dynamic stability
- System voltage stability

In most cases, conventional non-storage options are available to address these power quality challenges. For example, capacitors may be used for some reactive-power-related needs. Also, newer wind turbines will, by design, have reduced power quality impacts.[31]

3.6.3.4. Reduce Output Variability

This application is related to the need to offset generation output variability caused by natural wind speed variability over durations of several minutes to a few hours. Increasing wind generation penetration seems likely to increase the need for load following resources beyond what would otherwise be needed for a more dispatchable electric supply mix. It is important to note, however, that large, well-diversified electric supply and transmission systems can accommodate a lot of wind generation variability, especially if the wind generation is geographically diverse and/or comprises a relatively small portion of the electric supply capacity.[32]

This application is somewhat analogous to the 'load following' ancillary service application because of the time scales and operational profiles involved. In fact, at the grid level, system load following resources are used to compensate for such variations. Presumably, reducing aggregate wind generation variability will also reduce the need for central load following.

In more than a few regions, normal wind speed patterns mean that wind generation output drops off just as load picks up (*i.e.*, it decreases as people begin activities in the morning). Similarly, wind generation often increases as load drops off (*i.e.*, generation output rises as people's activity, and the associated electric load, decreases at night). In such a scenario, adding wind generation capacity may also increase the need for load following capacity. In the evening, the grid may need extra load following in the down direction to accommodate increasing wind generation output that occurs during times when load is decreasing. Because wind generation output drops in the morning just as load picks up, more load following in the up direction may be needed as new wind generation capacity is added.

Wind generation variability (and the corresponding need for load following resources) may be an especially compelling challenge during times when load is light. This is because, in many regions, a relatively small amount of *dispatchable* generation is available at those times to accommodate wind generation fluctuations (*i.e.*, the output of most generation online at those times tends to be coal-fired, nuclear, natural gas/steam, 'must-take' energy purchase contracts and some hydroelectric generation that cannot be reduced).[33]

Although requirements will be different for each location and area, for this report, it is assumed that storage capacity whose power rating is 4% to 6% of wind generation capacity could offset the need for a similar amount of system load following resources (*i.e.*, those load following resources *would* be needed to accommodate wind generation's natural variability, without storage).[34]

That range (4% to 6% of wind generation capacity for reducing output variability) applies to a geographically diverse wind resource with wind generation penetration levels of about 10% of total generation capacity. Presumably, the optimal amount of storage would change with wind generation penetrations above 10%.

3.6.3.5. Transmission Congestion Relief

This application reflects an important challenge posed by the installation of significant amounts of wind power capacity. At any given point in time, the transmission system may not have enough capacity to transfer the energy generated by all the wind turbines, causing 'congestion' on the grid (*i.e.*, too much energy to be transferred through the available transmission capacity). Storage could be used *in lieu* of upgrading transmission to accommodate wind generation during times when congestion occurs:

- Storage located *upstream* from the point of congestion could be charged when congestion occurs, so energy can be transmitted when there is no congestion.
- Storage located *downstream* from the point of congestion would allow for transmission of energy for charging when there is no congestion. That energy can be used later when congestion occurs.

3.6.3.6. Backup for Unexpected Wind Generation Shortfall

The need for storage backup for unexpected wind generation shortfall materializes when regional wind velocity is considerably lower than predicted and wind generation is supplying a relatively large portion of total grid power. Although such events are rare, the effect on the grid may be significant. As wind generation penetration increases, the impact from such events may also increase.

Consider one real-world example. On February 27, 2008, the state of Texas experienced an unexpected "drop in wind generation…coupled with colder than expected weather." During the event, wind generation output reportedly dropped from about 1,700 MW to about 300 MW. Grid operators responded by asking grid customers with interruptible electric tariffs to reduce power use by about 1 GW for about 90 minutes.[35] Two key options when this occurs are 1) to call on end users with interruptible or curtailable electric service or 2) to dispatch reserve capacity.

3.6.3.7. Reduce Minimum Load Violations

In some cases, wind generation output occurs when must-run and/or non-dispatchable generation capacity online exceeds demand. In this report, that situation is referred to as a minimum load violation. Possible alternatives for addressing minimum load violations may include 'dumping' or 'spilling' unusable energy or curtailing wind generation output. Storage may be especially helpful to manage those situations, especially if the minimum load violation results in 'negative prices', meaning that energy users get paid to take the energy.

3.6.3.8. Technical Considerations

Storage for wind-generation-related transmission congestion relief and for backup does not have any unique technical requirements. Ramp rate is not especially important, and reliability is not especially important if there are a large number of storage units in service.

Storage used to address wind output intermittency and power quality *must* have a rapid ramp rate. Storage used to address wind output intermittency will likely need to have a very high efficiency and low operation cost because that application involves many charge/discharge cycles per hour.

If reactive power capability is needed for power quality, then the storage system's PCU must have VAR support capability or must be able to produce reactive power.

3.6.3.9. Application Synergies

Generalizing application synergies for wind generation grid integration may not be especially helpful, as technical and operational needs for the six application subtypes vary so much. Nevertheless, there are many possible combinations, some of which may be attractive now or in the future. Especially notable are synergies with the renewables energy time-shift and renewables capacity firming applications; storage used with wind generation for those applications may also reduce grid effects from wind output variability incidentally.

Reducing output volatility is probably not compatible with any other application subtype or with any of the other primary applications described in this report because storage used to manage output volatility is almost always in service. Storage designed for the improved power quality application subtype probably has a short duration and thus may not be compatible with use for other applications.

Depending on the timing of storage output and the storage's location, storage used for the transmission congestion relief, reduce output variability, reduce minimum load violations, and backup for unexpected wind generation shortfall application subtypes may be compatible with each other or with several other primary applications.

If the storage is located at distributed locations (*i.e.,* for small commercial or even residential wind turbines), then storage could also be used for T&D upgrade deferral, electric service reliability, electric service power quality, TOU energy cost management, and demand charge management.

3.7. Distributed Energy Storage Applications

Locating storage near loads opens up opportunities to use the same storage for many more applications than a larger 'central' or 'bulk' resource could address. Depending on the location, storage deployed as a distributed energy resource (DER) may be compatible with all applications listed in this report except for area regulation, transmission support, and some wind integration-related uses.

3.7.1. Locational Distributed Storage Applications

The applications in this subsection are those that are *best* served by *distributed* storage or *cannot* be served unless the storage is deployed in distributed mode (*i.e.,* the storage is located where needed, near to loads). These applications include voltage support, transmission congestion relief, T&D upgrade deferral, TOU energy cost management, demand charge management, electric service reliability, electric service power quality, renewables capacity firming, and wind generation grid integration

For example, storage used to defer a T&D capacity upgrade must be located near loads served by the T&D equipment in question. More specifically, the storage must be located downstream (electrically) from the T&D node in question. Another example is storage used to improve localized power quality. That storage must be located where it actually provides the necessary effect(s) on power quality.

3.7.1.1. Voltage Support

For this report, distributed storage (*i.e.*, storage located near loads that most heavily affect voltage) is a viable option for the voltage support application, whereas voltage support provided centrally is assumed to be from large generation facilities. Unless the grid is weak or poor, storage will be used very little, if at all, for this application. Given that consideration, almost any storage located at or near loads that contribute to cascading outages could provide voltage support if it has VAR support capabilities and a discharge duration of 30 minutes or more.

3.7.1.2. Transmission Congestion Relief

If distributed storage is located downstream from congested transmission, then it could be used to store energy when there is no congestion and/or to reduce demand downstream from congestion when the congestion occurs. For distributed storage, this application/benefit may be especially compatible with the following applications/benefits: demand charge management, TOU energy cost management, electric supply reserve capacity, voltage support, electric service reliability, and electric service power quality.

3.7.1.3. T&D Upgrade Deferral

T&D upgrade deferral is one of the richest possibilities for distributed storage because the benefit can be so high. Also, this application/benefit may be compatible with several other applications/benefits, especially the following: electric supply reserve capacity, voltage support, electric service reliability, electric service power quality, TOU energy cost management, demand charge management, and possibly even electric supply reserve capacity and load following.

3.7.1.4. Time-of-use Energy Cost Management and Demand Charge Management

Bill management includes two closely related applications: TOU energy cost management and demand charge management. These applications are notable because storage used for them could also be used for electric service reliability, electric service power quality, electric supply reserve capacity (when charging and when charged but not discharging) and load following (when charging). Storage installed in advantageous locations could also provide voltage support, T&D upgrade deferral, and transmission congestion relief.

3.7.1.5. Electric Service Reliability and Electric Service Power Quality

Electric service reliability and electric service power quality are especially notable applications because significant demand for storage already exists in the form of uninterruptible power supplies (UPSs). They are also notable because, in most cases, storage can provide significant benefit with limited charging/discharging and relatively short discharge durations. In many cases, storage used for several distributed storage applications could also provide backup energy for electric service reliability and could be used to condition power as needed to address power quality problems.

3.7.1.6. Renewables Capacity Firming – Photovoltaics

There are strong synergies when modest storage capacity is coupled with on-site PV. Although PV production may not coincide with *capacity* needs, most PV production occurs during times when most energy is used, and PV alone cannot provide emergency or backup power without sunlight. Distributed storage used to firm PV capacity may also be compatible with other applications, including demand charge management, TOU energy cost management, electric supply reserve capacity, voltage support, electric service reliability, and electric service power quality.

3.7.1.7. Wind Generation Grid Integration

New wind turbine concepts may lead to increasing use of distributed wind generation capacity. As noted in the discussion of the wind generation integration application (Section 3.6), storage may be important if there will be even modest penetration of wind generation capacity at the distribution level. Depending on the circumstances, wind generation's energy could be sold to the grid at a profit or used to reduce TOU energy charges. Also depending on the circumstances, firming wind generation capacity with storage may provide capacity value if the utility has a need for the firm capacity and/or if the end user can use it to reduce demand charges.

3.7.2. Non-locational Distributed Storage Applications

For the following applications, distributed storage may be located anywhere that its operation does not cause operational or technical problems for the grid: electric energy time-shift, electric supply capacity, load following, area regulation, electric supply reserve capacity, and renewables energy time-shift.

3.7.2.1. Electric Energy Time-shift

Assuming that distributed storage is not subject to transmission congestion during charging, distributed storage could be used to store inexpensive off-peak electric energy from the grid so that the energy may be used or sold when value/price is high.

3.7.2.2. Electric Supply Capacity

As with electric energy time-shift, if distributed storage is not subject to transmission congestion when charging occurs, it can be used to store inexpensive off-peak electric energy from the grid so that the energy may be used for electric supply capacity firming when doing so is valuable.

3.7.2.3. Load Following

To the extent that distributed storage can respond to control signals from the ISO, it can be used for load following. Perhaps most interesting is the possibility of providing load following, incidentally, while charging. (See Section 3.3.1 for details.)

3.7.2.4. Area Regulation

Conceptually, area regulation could be provided anywhere within an area if the location does not have any transmission constraints. If the area regulation capacity is located downstream (electrically) from subtransmission or distribution equipment, there may be some back-feed constraints if the equipment cannot accommodate a significant amount of energy flow into the transmission system. If so, then perhaps the area regulation capacity could be matched to local area regulation needs.

3.7.2.5. Electric Supply Reserve Capacity

Distributed storage that is charging or that is in standby mode can provide reserve capacity. Notably, unless the electric supply system served is weak or poorly managed, storage will be used very little for reserve capacity.

3.7.2.6. Renewables Energy Time-shift

As the electricity marketplace evolves, there may be opportunities for using distributed energy storage to store energy generated by large renewable-fueled generation located upstream from transmission and/or distribution system bottlenecks. Key objectives include increasing renewables' energy and capacity value and relieving grid system congestion. This seems especially valuable if distributed storage can be charged when minimum load conditions exist (or even when less severe mismatches between supply and load exist); and/or when charging can be used for load following; and when transmission congestion is not a challenge.

3.7.3. Incidental Applications from Distributed Storage

Distributed storage can serve some applications, incidentally, while charging – most notably load following and electric supply reserve capacity. If the distributed storage (which is charging) has enough *stored* energy then it can also *discharge* to provide *additional* electric supply reserve capacity for other applications including voltage support, electric service reliability, and electric service power quality. Note that reduced storage charging has the same effect as adding reserve capacity. If, after charging is stopped, that same storage then *discharges* into the grid or picks up load, then the storage essentially provides two times its capacity as reserve capacity.

Similarly, distributed storage that is charged can serve several applications, incidentally, while in standby mode (*i.e.*, while not being used for a primary application) including electric supply capacity, voltage support, electric service reliability, and electric service power quality.

3.8. Applications Not Addressed in this Guide

It is important to note that the approach used for this report – involving applications that are defined based on the corresponding electric utility-related benefit – may seem to exclude many possible *uses* of storage. Certainly, that was not the authors' intention. Indeed, the framework developed for this report can be used to estimate the financial benefits associated with many uses of storage, including many not addressed explicitly, because the benefits described are intended to address the various *revenues and avoided costs* that accrue when storage is used.

Consider three examples of storage use: 1) as a backup power source for telecommunications facilities, 2) as part of a rail system to address voltage sags and to recuperate energy using regenerative braking, and 3) for localized reactive power compensation (VAR support) by utilities.

For the first example (backup for telecom facilities), the benefit is related to avoided outages. The magnitude of the benefit can be estimated using an approach similar to that described in this report for the electric service reliability benefit. Specifically, the benefit is either the cost avoided because a more expensive alternative (*e.g.,* diesel engine generators) is not needed if storage is used, or the application-specific value of avoided unserved energy.

The benefit for use of storage in the second example (rail system trackside storage) is some combination of reduced cost for other equipment needed to address the voltage sag challenge; reduced cost to purchase energy; and reduced peak demand charges. In many cases, the equipment purchases that are deferred or avoided are for additional circuits and/or transformers and/or power electronics.

In the third example (utility use of storage for VAR support), the benefit is the avoided cost for equipment that would have to be installed without storage, normally capacitors.

4. Maximum Market Potential Estimation

This section describes a framework for making a high-level, 'first-cut' estimate of the market potential for storage for each of the applications characterized herein (see Figure 13). It entails a generic, three-step process. Estimates for steps one and two are provided in this guide. Taking the estimate to the final step is beyond the scope of this report, as making it requires detailed analysis involving, among other criteria and considerations, 1) a broad array of national and regional market conditions, drivers, and trends; 2) utility regulations and rules; 3) technology cost and performance, existing and trends; 4) the spectrum of benefits (values) for individual applications and for viable application combinations (value propositions); and 5) stakeholder biases and preferences.

4.1. Market Potential Estimation Framework

As indicated by the outer square in Figure 13, the first step required when estimating economic market potential is to ascertain the *technical* market potential. It is the maximum amount (MW) possible given technical constraints. As an upper bound, the technical potential is the peak electric demand.

Next, the *maximum* market potential is established. As shown in Figure 13, maximum market potential is a portion of the technical potential. It is an estimate of the maximum possible demand given constraints that are practical or institutional in nature (*e.g.*, utility regulations and practices). Maximum market potential is also established without regard to storage cost.

Finally, an estimate would be made of the *expected* market potential (market estimate). As shown in Figure 13, the market estimate is some portion of the maximum market potential. The market estimate reflects the amount of storage that an analyst expects to be deployed, over a given period of time (10 years in this document), for the specified application or combination of applications.

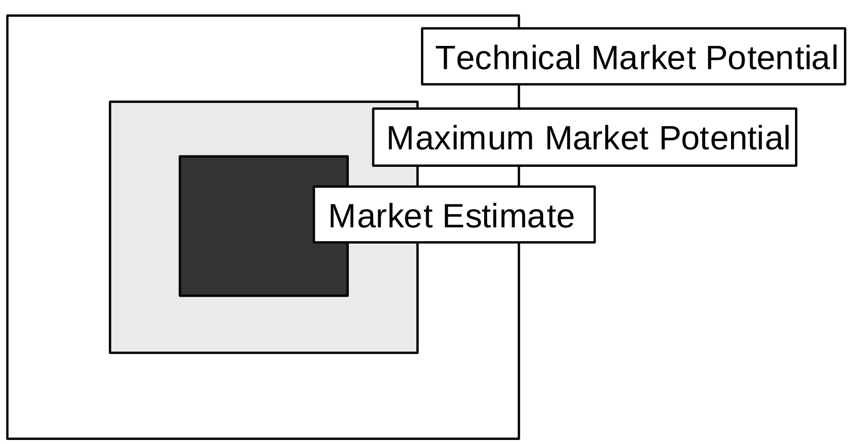


Figure 13. Market potential and estimate.

Market estimates may be as detailed and precise as appropriate. At the very least, various levels of market potential can be tested for reasonableness using a combination of judgment, knowledge, and preliminary product cost estimates. Alternative bases for estimates could include, for example, sales trends and projections, surveys, analysis of utility capital budget plans, detailed product cost estimates, and/or market research or intelligence.

4.1.1. Role of Aggregators

For some applications, and for electricity end users that do not use a lot of energy, the hassle, learning curve, and transaction costs may make using storage and other modular or distributed options too expensive, despite attractive benefits. In a growing number of areas, there may be load and distributed resources aggregators that combine several or many smaller end users in a given area into what could be called power blocks. (See Section 6.5.4 for details.)

4.2. Technical Potential: Peak Electric Load

A key parameter that underlies the maximum possible market size is the total electric load (kW or MW) served by the grid. Market potential is some portion of that peak load. The values in Table 8 include projected peak load in the U.S. and California. The values for the U.S. are based on information from NERC.[36] Visit the NERC website (nerc.com) for details. Values for California are published by the CEC. Visit the CEC website (energy.ca.gov) for details. (Note that the CEC website refers to peak *demand* rather than peak *load*.) The 2008 peak load in California was approximately 62,946 MW, comprising 8% of the total U.S. peak load.[37][38]

Table 8. U.S. and California Peak Load and Peak Load Growth

	California[1]	U.S.[2]
Peak Load, 2008 (MW)	62,946	796,479
Generation Capacity, 2008 (MW)	76,794	925,916
Reserve Margin (%)	22.0%	16.3%
Expected Peak Load Growth Rate (%/year)	1.37%	1.80%
Load Forecast, 2017 (MW)	72,235	920,850
Load Growth Estimate, 2008 to 2017 (MW)	9,289	124,371

[1]Source: California Energy Comission (CEC)
[2]Source: North American Electric Reliability Council (NERC).

4.3. Maximum Market Potential

The maximum market potential for all applications in this guide is the upper bound to the market estimate. It is established by considering constraints (on market potential) that are practical and institutional. Maximum market potential is established without regard to storage cost. For example, given the premise that it is unlikely that storage will displace *existing* utility equipment, a simplifying assumption (for utility applications) is that the market for new storage to serve electric load is limited to some portion of the annual load *growth*. For specific applications, other practical or institutional limits on the maximum market potential apply. For example, if the application is for a commercial or industrial customer, then residential customers are not part of the maximum market potential.

4.3.1. Maximum Market Potential Estimates

Maximum market potential estimates for 17 electric-grid-related energy storage applications are shown in Table 9. Estimates for California and U.S. markets are provided, as are the key assumptions and the rationale used to establish those estimates.

Table 9. Maximum Market Potential Estimates

		Maximum Market Potential (MW, 10 Years)		
#	Type	CA	U.S.	Note
1	Electric Energy Time-shift	1,445	18,417	10% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
2	Electric Supply Capacity	1,445	18,417	Same as above.
3	Load Following	2,889	36,834	Total load following = 20% of peak load, 20% of that, maximum, served by storage.
4	Area Regulation	80	1,012	Per CEC/PIER study involving Beacon Power flywheel storage for regulation.
5	Electric Supply Reserve Capacity	636	5,986	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
6	Voltage Support	722	9,209	5% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
7	Transmission Support	1,084	13,813	1.5% of peak demand, per EPRI/DOE report.
8	Transmission Congestion Relief	2,889	36,834	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
9.1	T&D Upgrade Deferral 50th percentile	386	4,986	T&D upgrade needed for 7.7% of peak load. Of that, a maximum of 50% of qualifying peak load is served by storage. Storage = 3.0% of peak load, on average.
9.2	T&D Upgrade Deferral 90th percentile	77	997	
10	Substation On-site Power	20	250	2.5 kW per system
11	Time-of-use Energy Cost Management	5,038	64,228	67% of peak load is assumed to be in-play. 1%/yr storage adoption rate.
12	Demand Charge Management	2,519	32,111	33% of peak load is assumed to be in-play. 1%/yr storage adoption rate.
13	Electric Service Reliability	722	9,209	10% of peak load is assumed to be in-play, 10% of that, maximum, served by storage.
14	Electric Service Power Quality	722	9,209	Same as above.
15	Renewables Energy Time-shift	2,889	36,834	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
16	Renewables Capacity Firming	2,889	36,834	Same as above.
17.1	Wind Generation Grid Integration, Short Duration	181	2,302	10.0% of peak load is in play. Add storage equal to as much as 2.5% of that amount for intermittency.
17.2	Wind Generation Grid Integration, Long Duration	1,445	18,417	10% of peak load from wind gen., Add storage to a maximum of 20% of that.

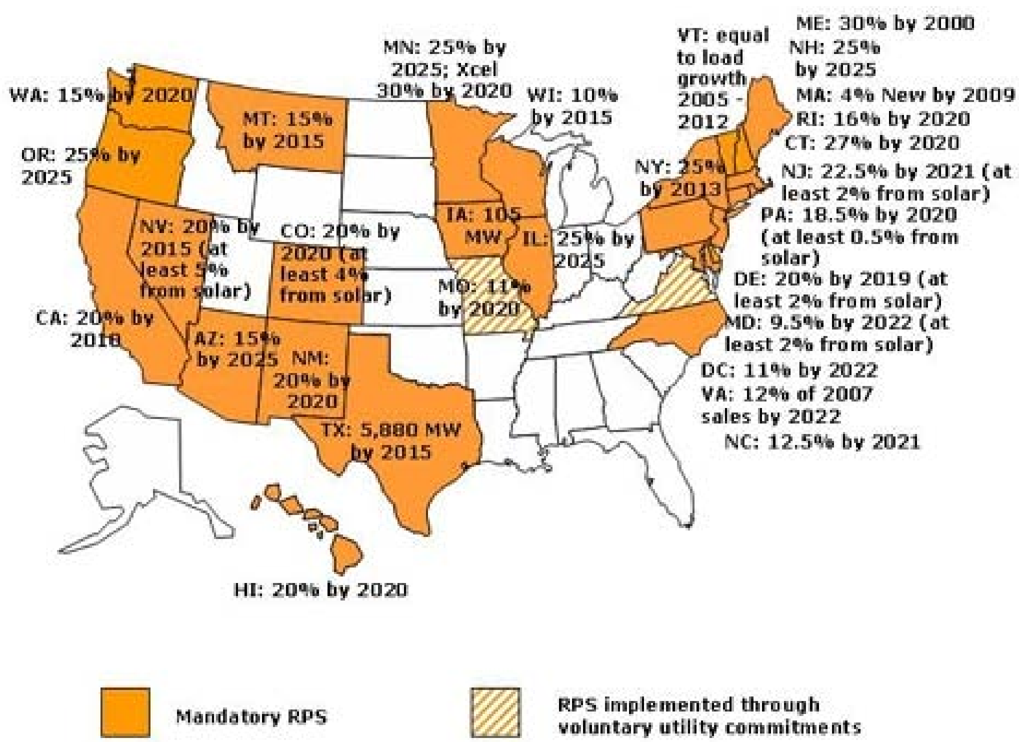
The term "in-play" indicates the maximum portion of peak demand that is assumed to be addressable with storage w/o regard to market or technical constraints. Maximum market potential is some portion of that amount.

4.3.1.1. *Caveats about Maximum Market Potential Estimates*

The rationale used to establish the above maximum market potential estimates was designed to be transparent (all assumptions used are presented). The values were developed based on a combination of the authors' and supporting analysts' experience and familiarity with the following: energy storage technology; utility loads and supply including costs and prices; utility biases, rules and regulations; electricity market-related business opportunities for energy storage and for modular and distributed resources; and market acceptance of new technologies in the electricity marketplace. Some estimates are based on a relatively high degree of speculation, due to both the dearth of information about the topic and the nascent nature of demand for storage for the applications covered herein. To the extent that analysts have superior and/or newer information, they are encouraged to update or modify these estimates as appropriate.

4.3.2. Renewables Portfolio Standard

Renewable energy seems poised to become a significant fuel source for electric generation. In the U.S., the Renewables Portfolio Standard (RPS) is expected to be a key driver of the trend toward renewables for electricity. Figure 14 indicates RPS-related targets, by state, as of 2008.[39] In this guide, it is assumed that by 2017 15% of electric energy (MWh) in the U.S. will be generated using renewables, and two-thirds of that will be from wind generation.



Source: Pew Center Website about Climate Change (as of 2008). http://www.pewclimate.org/

Figure 14. U.S. Renewables Portfolio Standard targets by state.

4.4. Market Estimate

The final step in the market estimation process is to consider the portion of the maximum market potential that will be realized during the target period. The market estimate should be as detailed and precise as appropriate. At the very least, various levels of market potential can be tested for reasonableness using plausible combinations of judgment, knowledge, or preliminary product cost estimates. Alternative bases for estimates could include, for example, sales trends and projections, surveys, analysis of utility capital budget plans, detailed product cost estimates, or market research or intelligence. Note that a market estimate is product-specific and organization-specific, making generic market estimates unhelpful, so none are provided in this report.

4.4.1. Important Considerations

Important criteria affecting market estimates for storage systems include system cost (capital, installation, operation and maintenance, *etc.*), efficiency, marketing costs, market adoption rates, and other considerations discussed in more detail below.

4.4.1.1. Price Signals or Risk and Reward Sharing Mechanisms Must Exist

To include potential demand in the estimate, the region where the demand exists must have price signals or risk and reward sharing mechanisms in order for a given stakeholder to internalize the benefit(s) associated with the targeted value proposition. For example, if utility rules and regulations do not provide adequate incentive for a utility to defer a T&D upgrade, then the T&D deferral application does not apply in that region. Or, if a wind farm developer cannot get a credit for reducing electric service power quality impacts, then that application does not apply in the region.

4.4.1.2. Utility Rules and Regulations Should Give Explicit Permission

It is important to account for utility rules and regulations that forbid use of storage for a given application when making estimates.

4.4.1.3. Storage Must Be Cost Effective

One obvious driver of the market potential for storage systems (used for a given application or applications) is the value proposition to be demonstrated. Specifically, if the cost for storage is higher than the lifecycle benefits, then no storage systems will be sold. If benefits exceed cost by a large margin, then the amount of storage used could be significant.

4.4.1.4. Storage Must Be Cost Competitive

As described in Section 5, benefits associated with the use of energy storage are estimated irrespective of the specific solution being considered. It is important to note that the competitiveness of a given solution (storage or other acceptable substitutes) depends on whether there is a lower cost and/or another viable option.

When establishing the maximum market potential estimate, it is important to account for the fact that solutions whose costs are not competitive are not attractive candidates. Specifically, storage systems whose cost exceeds the cost of another technically viable option are not financially competitive solutions.

4.4.1.5. Changing Electricity Supply and Demand: Effect on On-peak **versus** *Off-peak Electric Energy Price Differential*

Two important premises affect the prospects for utility-related use of storage:

1. There are times when electric energy prices are low — because energy *use* is low and because efficient power plants are on the margin, usually at night.
2. There are times when energy prices are high — because energy *use* is high and because inefficient generation is on the margin, usually during the day, especially midday, on weekdays.

Consequently, there is a significant price difference (price delta) between the off-peak price and the on-peak price for electric energy. Nevertheless, there are electric energy supply and demand considerations that could lead to a modest to significant reduction in that price delta. Perhaps most important is the expected increase in the use of plug-in electric vehicles (PEVs) and plug-in hybrid electric vehicles (PHEVs). If a significant number of these vehicles *are* used, then presumably there would be downward pressure on the price delta because more electric energy will be needed during off-peak periods. Similarly, if a lot of energy storage is installed for the applications described in this guide, then additional upward pressure will be exerted on the off-peak price for electric energy. Other possibilities include the increased use of electric energy during off-peak periods to serve loads if, for example, increased economic activity leads to more business and manufacturing activities at night and upward pressure on price for generation fuel used off-peak.

4.4.2. Market Estimates for Combined Applications and Benefits

In many cases, storage may be used for more than one application. When making market estimates for these circumstances, it is important that estimates account for the fact that combining applications may increase storage system benefit ($/kW) while reducing the overall market potential.

Four possible reasons that it may be inappropriate to add the entire market potential for one benefit to the entire market potential for another benefit are as follows:

1. Some benefits accrue to separate stakeholders.
2. Some applications/benefits are region- or location-specific.
3. For most applications the value (magnitude of the benefit) varies among possible beneficiaries.
4. Not all beneficiaries for one benefit ascribe value to the other benefit.

Consider an example: A storage plant is used for the T&D upgrade deferral application. If storage benefits also accrue for electric service reliability, then the estimated market potential is based on the intersection between the market estimate for T&D upgrade deferral alone and the market estimate for electric service reliability alone. The resulting estimate indicates the market potential for customer load that is served by T&D equipment that is due to be upgraded *and* that requires high electric service reliability. This concept of application/benefit intersection is illustrated in Figure 15.

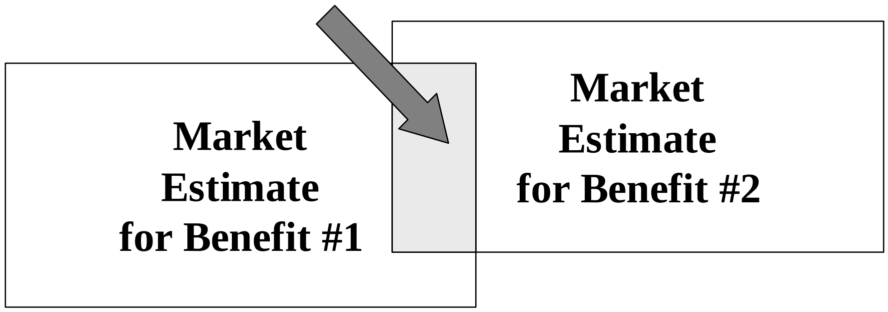


Figure 15. Market intersection.

Consider another example: Utility customers will use energy storage for demand charge management, electric service reliability, and electric service power quality. Market estimates would account for the following:

- Technical market potential encompasses all commercial and industrial electricity end users.
- Only a portion of those end users pay demand charges.
- For many commercial and industrial electricity end users that pay demand charges, the benefit associated with increased electric service reliability may be relatively low (depending on the value of the products and/or services involved).
- Only a portion of customers that pay demand charges and that are concerned with electric service reliability will derive a financial benefit from improved power quality.

Similarly, if storage is used for TOU energy cost management *and* for electric service reliability, then some electricity end users who need improved reliability may not pay based on TOU energy prices, and conversely, all end users who pay TOU energy prices may not need improved reliability.

5. Storage Benefits

5.1. Introduction

This section discusses the calculation of *application-specific* financial benefits (benefits) associated with using storage for the 17 applications described in Section 3. Also characterized are nine *incidental* benefits that may accrue if storage is used for one or more of the 17 applications. The 26 application-specific and incidental benefits are listed in Table 10.

Table 10. Application-specific and Incidental Benefits of Using Energy Storage

Application-specific Benefits	
1.	Electric Energy Time-shift
2.	Electric Supply Capacity
3.	Load Following
4.	Area Regulation
5.	Electric Supply Reserve Capacity
6.	Voltage Support
7.	Transmission Support
8.	Transmission Congestion Relief
9.	Transmission and Distribution (T&D) Upgrade Deferral
10.	Substation On-site Power
11.	Time-of-use (TOU) Energy Cost Management
12.	Demand Charge Management
13.	Electric Service Reliability
14.	Electric Service Power Quality
15.	Renewables Energy Time-shift
16.	Renewables Capacity Firming
17.	Wind Generation Grid Integration
Incidental Benefits	
18.	Increased Asset Utilization
19.	Avoided Transmission and Distribution Energy Losses
20.	Avoided Transmission Access Charges
21.	Reduced Transmission and Distribution Investment Risk
22.	Dynamic Operating Benefits
23.	Power Factor Correction
24.	Reduced Generation Fossil Fuel Use
25.	Reduced Air Emissions from Generation
26.	Flexibility

Readers should note that the emphasis in this document and this section is on the financial *benefit* of storage, with very limited regard to the *cost* associated with owning and operating storage systems. Nevertheless, the benefit estimate *is* intended as a general indication of the cost at which storage is competitive.

5.1.1. Benefit Definition

5.1.1.1. Benefit Basis

In broad terms, benefits from storage can take two forms: 1) additional revenue received by the storage owner/operator or 2) cost that is avoided by the storage owner/operator (avoided cost). Examples of additional revenue include payments received for a) energy sales, b) capacity, and c) ancillary services. Examples of avoided cost associated with storage use include a) a utility's reduced or avoided need (and cost) for generation or T&D capacity and b) a utility customer's reduced cost for energy and demand charges.

Avoided cost can have at least three forms. First, if storage is the only viable alternative, then avoided cost involves the negative outcomes associated with doing nothing. Second, if storage is used *in lieu* of a conventional/standard solution, then avoided cost is the total cost that would have been incurred for the conventional/standard solution is used (where total cost includes purchase, installation, operation, and removal and disposal). Third, if there are several viable alternatives, then the avoided cost is alternative with the lowest total cost (where total cost includes cost to purchase, install, operate, and remove for disposal).

Avoided Cost for the Do Nothing Alternative

In some cases, the leading alternative is to 'do nothing.' Do nothing is a common option for needs that are relatively unlikely to materialize and/or that are expensive. Consider the example of a distribution circuit that is heavily loaded. If there is only a one-in-ten chance that overloading will occur, then the do nothing alternative may be preferable to installing an upgrade, especially if the upgrade is expensive.

Avoided Cost for the Conventional/Standard Solution

In most cases, especially those involving utilities, the benefit for storage is established based on the cost for a conventional/standard alternative. That is, if storage is to be used *in lieu* of a standard/conventional alternative then the benefit (associated with storage use) is the (avoided) cost for the standard/conventional alternative. This concept is especially important for utilities for which the conventional/standard alternative is mandated by legislation and/or regulation.

Consider the possibility that a utility would use storage to improve localized electric service reliability. The conventional/standard alternative competing with storage is whatever the utility would normally do to improve reliability. Those alternatives may range from adding equipment to manage the causes of outages to a full T&D upgrade, involving alternate circuits and transformers. Consider another example: Due to load growth, a utility needs to upgrade its T&D equipment; however, use of storage could defer or to avoid the need to make the upgrade. In that case, the storage-related benefit is the avoided cost associated with deferring or avoiding the need for the conventional/ standard alternative which is the T&D upgrade.

Avoided Cost for the Lowest Cost Viable Alternative

In some cases, the storage benefit could be based on the cost of the lowest cost alternative that is otherwise viable. Consider the possibility that a utility customer could add facility-scale storage for time-of use energy cost management and demand charge management plus electric service reliability. In that case, the lowest cost viable alternative could be energy efficiency measures plus under-desk UPSs and/or on-site backup generation.

5.1.1.2. *Gross* versus *Net Benefit*

For most benefit types, the *gross* benefit value is calculated. That is, benefits are estimated without regard to the cost. The benefit estimate is intended to provide a general indication of the price point required for storage to be financially viable. So, if storage can be owned and operated for an amount less than the estimated benefit, then the value proposition may be financially viable.

The one notable exception is electric energy time-shift. For that application, the financial merits of each possible hourly ‘buy-low/sell-high’ transaction must be calculated before the transaction is made, based on the difference between the benefit for the energy that is discharged *versus* the marginal cost to get that energy. Storage marginal cost includes variable operating cost, charging energy cost, and the cost for energy losses. So, the estimated benefit for electric energy time-shift is net of storage marginal cost.

5.1.1.3. Benefit Financials

For this guide, the financial benefit is defined as the total lifecycle financial benefit associated with use of storage. Although, arguably, some benefits cannot be quantified, only benefits that can be expressed in financial terms are included. For this document, storage is assumed to be in use for 10 years, the assumed price escalation is 2.5%, and the discount rate is 10%. (See Section 1.6.1 for more details about the approach used to address storage financials.)

5.1.2. Benefits Summary

Table 11 summarizes the benefit values characterized later in this section.

Table 11. Application-specific Benefit Estimates

#	Type	Benefit ($/kW)* Low	High	Note
1	Electric Energy Time-shift	400	700	Low: 80% efficiency, 2¢/kWh VOC, 4 hours. High: 80% efficiency, 1¢/kWh VOC, 5.5 hours.
2	Electric Supply Capacity	359	710	Low: mid/peak duty cycle combustion turbine, cost $50/kW-year. High: combined cycle combustion turbine, cost $99/kW-year.
3	Load Following	600	1,000	Low: simple cycle combustion turbine, price $20/MW per service hour. High: combined cycle combustion turbine, price $50/MW per service hour.
4	Area Regulation	785	2,010	Low: $25/MW per hour, 50% capacity factor. High $40/MW per hour, 80% capacity factor. For up regulation *and* down regulation.
5	Electric Supply Reserve Capacity	57	225	Low: $3/MW per hour, 30% capacity factor. High $6/MW per hour, 60% capacity factor.
6	Voltage Support	400	800	Low: prevent 1 outage lasting 1 hour over 10 years. High: prevent 2 outages lasting 1 hour over 10 years. Storage = 5% of load.
7	Transmission Support	192		Based on DOE/EPRI storage report[14].
8	Transmission Congestion Relief	31	141	Based on CAISO congestion prices in 2007.
9.1	T&D Upgrade Deferral 50th percentile	481	687	Low: upgrade factor = 0.25. High: upgrade factor = 0.33.
9.2	T&D Upgrade Deferral 90th percentile	759	1,079	Same as above.
10	Substation On-site Power	1,800	3,000	Based on cost for standard storage solution.
11	Time-of-use Energy Cost Management	1,226		Based on PG&E's A6 time-of-use tariff. Six hours of storage discharge duration.
12	Demand Charge Management	582		Based on PG&E's A6 time-of-use tariff. Six hours of storage discharge duration.
13	Electric Service Reliability	359	978	Low: $20/kWh * 2.5 hours/year of avoided outages for 10 years. High: 10 Years of UPS Cost-of-ownership (present value).
14	Electric Service Power Quality	359	978	Low: avoided power quality related cost, 10 years. High: UPS cost-of-ownership, 10 years (present value).
15	Renewables Energy Time-shift	233	389	Low: bulk wind generation. High: baseload RE generation.
16	Renewables Capacity Firming	709	915	Low: fixed orientation distributed PV. High: bulk wind generation.
17.1	Wind Generation Grid Integration, Short Duration	500	1,000	Though the estimated *benefit* is relatively high, a modest amount of storage (<0.1 kW) is needed per kW of wind generation.
17.2	Wind Generation Grid Integration, Long Duration	100	782	Low: avoid 1 outage in 10 years from wind generation shortfall. High: high estimate of benefit for reduced transmisison congestion.

*Based on potential (kW, 10 years) times the average of low and high benefit estimates ($/kW, 10 years).

5.1.3. Economic Impact Summary

Table 12 summarizes the estimated economic impact from storage used for specific applications, given the estimated application-specific benefit and maximum market potential.

Table 12. Application-specific Potential Economic Impact Estimates

		Economic Potential ($Million)*	
#	Type	CA	U.S.
1	Electric Energy Time-shift	795	10,129
2	Electric Supply Capacity	772	9,838
3	Load Following	2,312	29,467
4	Area Regulation	112	1,415
5	Electric Supply Reserve Capacity	90	844
6	Voltage Support	433	5,525
7	Transmission Support	208	2,646
8	Transmission Congestion Relief	248	3,168
9.1	T&D Upgrade Deferral 50th percentile	226	2,912
9.2	T&D Upgrade Deferral 90th percentile	71	916
10	Substation On-site Power	47	600
11	Time-of-use Energy Cost Management	6,177	78,743
12	Demand Charge Management	1,466	18,695
13	Electric Service Reliability	483	6,154
14	Electric Service Power Quality	483	6,154
15	Renewables Energy Time-shift	899	11,455
16	Renewables Capacity Firming	2,346	29,909
17.1	Wind Generation Grid Integration, Short Duration	135	1,727
17.2	Wind Generation Grid Integration, Long Duration	637	8,122

*Based on potential (kW, 10 years) times the average of low and high benefit estimates ($/kW, 10 years).

5.2. *Application-specific Benefits*

5.2.1. Benefit #1 — Electric Energy Time-shift

5.2.1.1. Description

The annual financial benefit for electric energy time-shift (time-shift) is derived by using storage to make many electric energy buy-low/sell-high transactions. For a utility, the benefit may take the form of either lower energy cost or profit (if the energy is sold in the energy marketplace). For other stakeholders, the benefit is internalized as profit.[40]

To estimate the time-shift benefit, a simple storage dispatch algorithm is used. The algorithm contains the logic needed to determine when to charge and when to discharge storage in order to optimize the financial benefit. Specifically, it determines when to buy and when to sell electric energy, based on price. In simplest terms, the dispatch algorithm evaluates a time series of prices to find all possible transactions in a given year that yield a net benefit (*i.e.*, benefit exceeds cost). The algorithm keeps track of net benefits from all such transactions for the entire year to estimate an *annual* time-shift benefit. One key point regarding the approach used for this guide is worth noting: the results reflect 'perfect knowledge'. That is, a predetermined series of projected prices was used. In effect, at any given hour in the year, the algorithm 'knows' what prices will be at any other hour of the year.

Three data items are used in conjunction with the dispatch algorithm:

- Chronological hourly price data for one year (8,760 hours)
- Energy storage round-trip efficiency
- Storage system discharge duration

The chronological hourly price data used are the projected hourly electric energy prices in California for 2009.[41] Figure 16 shows prices for the entire year. Based on this data, there are about 900 hours per year when the price is above $100/MWh (10¢/kWh). During off-peak periods (when storage plants are charged), the price is frequently at about $50/MWh to $60/MWh (5¢/kWh to 6¢/kWh). (See Appendix F for more details about energy prices used.)

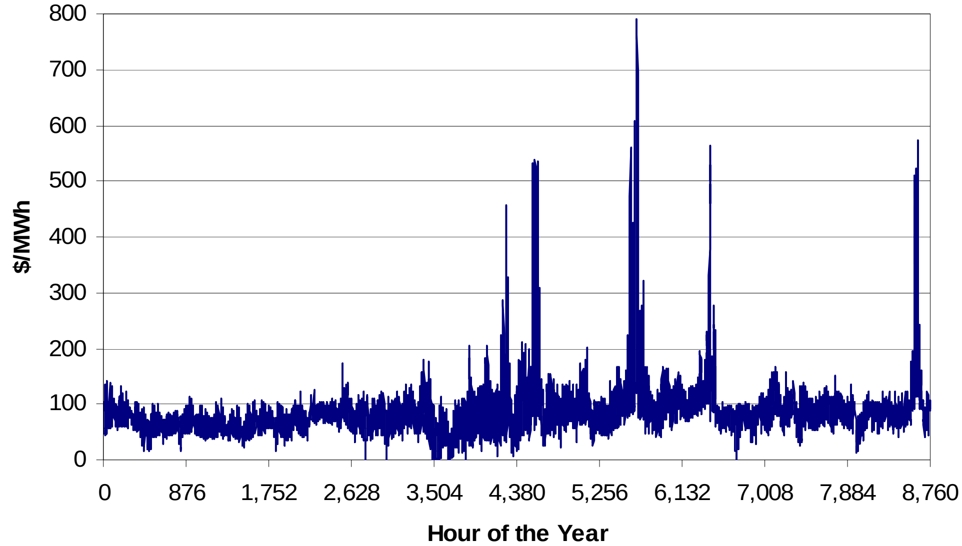


Figure 16. Chronological electricity price data for California, 2009 (projected).

Unlike the other benefits estimated in this report, the benefit for electric energy time-shift is expressed in terms of benefit net of *variable* cost. That is, before a decision is made to make any specific buy-low/sell-high transaction, the financial merits of that transaction are determined based on the cost (to purchase, store, and discharge the energy) *versus* the expected benefit (revenue or cost reduction).

If the cost for wear on the storage system, plus the cost for charging energy, plus the cost to make up for storage losses exceeds the expected benefit, then the transaction is not made. For example, 3 ¢/kWh energy could be used to charge an 80% efficient storage plant whose variable operating cost is also about 3¢ for each kWh of storage output. After accounting for storage energy losses, the total cost to charge and then to discharge is about 6.6 ¢/kWh. So, if the energy is worth more than 6.6 ¢/kWh, then the transaction is a good one.

One other consideration regarding the electric energy time-shift benefit is worth noting. The benefit for electric energy time-shift is based, in large part, on the differential between on-peak and off-peak energy prices. Even somewhat modest deployment of storage for PEVs or PHEVs and/or for utility applications could lead to a non-trivial decrease in that all-important difference between on-peak and off-peak energy prices. That would affect the potential benefit for energy time-shift.

5.2.1.2. Estimate

The storage dispatch algorithm is used to estimate the electric energy time-shift benefit for a given year. Figure 17 shows the estimated net electric energy time-shift benefit for storage systems. The three plots in that figure are for storage with the following (non-energy) variable operating costs (maintenance and replacement cost per kWh_{out}): 1) nothing, 2) 1¢/kWh_{out}, and 3) 2¢/kWh_{out}. Note that if that non-energy variable operating cost (VOC) exceeds 2¢/kWh, then the number of cost-effective transactions in a given year drops precipitously.

The *spread* shown for each plot in Figure 17 reflects the net benefit for storage efficiencies ranging from 70% to 90% and for storage whose discharge duration ranges from one to eight hours. As the hours of storage discharge duration increase, initially the incremental benefit increases too, but the increase eventually levels off. That reflects the diminishing benefit per buy-low/sell-high transaction. The benefit decreases because storage with longer discharge duration requires charging during more hours per year. It also decreases because the additional energy used for charging is probably more expensive and the selling price is probably lower, yielding a diminishing benefit per kWh discharged.

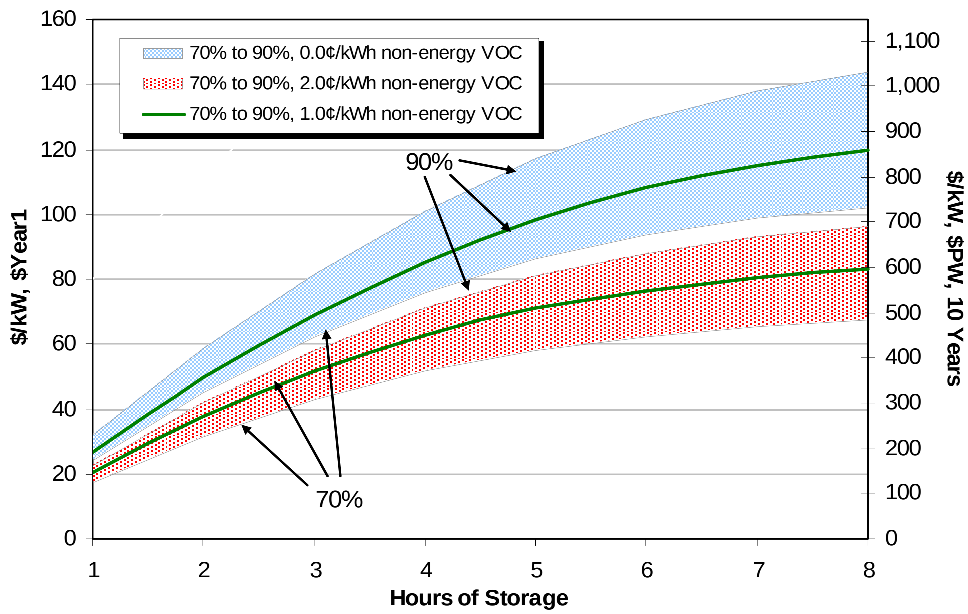


Figure 17. Annual and 10-year present worth time-shift benefit.

To estimate the lifecycle benefit for storage that provides electric energy time-shift service for 10 years, multiply the respective annual value by the 7.17 PW factor. The present worth of benefits is shown in Figure 17 on the second Y axis. The generic benefit estimate for electric energy time-shift ranges from $60/kW-year to $100/kW-year for lifecycle benefits ranging from approximately $400/kW to $700/kW.

5.2.2. Benefit #2 — Electric Supply Capacity

5.2.2.1. Description

In areas where electric generation capacity is limited, energy storage could be used to offset the need to purchase and install new generation and/or to offset the need to ‘rent’ generation capacity in the wholesale electricity marketplace. The resulting cost reduction (or avoided cost) is the benefit associated with storage used for the electric supply capacity application. Another possibility for ascribing a financial value to this benefit is price-based, where price is set by the electricity marketplace or by a designated agency, probably at the wholesale level. If applicable, electric supply capacity prices could be used to estimate this benefit.

5.2.2.2. Estimate

It is important to note that, in many wholesale electricity markets, generation capacity cost is not separated from energy costs. In those regions, the generation capacity cost is embedded in the price per unit of energy purchased. In such cases, there is no *explicit* capacity cost or charge that can be avoided, nor is there a way to sell generation capacity. Nonetheless, there is a capacity cost which is borne by electricity end users, irrespective of how the cost is recouped.

For many regions, the most likely type of new generation plant 'on the margin' is a clean, efficient natural-gas-fired combustion turbine-based power plant (state-of-the-art combined cycle or advanced simple cycle configuration) that operates for 2,000 to 6,000 hours per year.

The generic installed cost assumed for this guide is $1,000/kW. A typical annual fixed operation and maintenance (O&M) cost for such as plant is assumed to be $10/kW-year ($2007).[42] Applying the standard value of 0.11 for the utility fixed charge rate yields an annual cost of ownership of

$$\$1{,}000/\text{kW} \times 0.11 = \$110/\text{kW-year.}$$

After adding the $10/kW-year fixed O&M cost, the total annual cost for the generation *capacity* is $120/kW-year. Applying the PW factor of 7.17, the lifecycle benefit (for a storage plant used for 10 years) is

$$\$120/\text{kW-year} \times 7.17 = \$860/\text{kW.}$$

Arguably, $120/kW-year represents the maximum value for cases involving combustion-turbine-based generation, on the margin. A more conservative value would probably reflect either the cost to contract for or to own older, less efficient, higher maintenance generation – either steam-based or simple cycle combustion-based. As a lower bound, it is assumed that low-cost electric supply capacity has an equipment cost of $50/kW-year plus $10/kW-year for fixed O&M, yielding a total cost of $60/kW-year.

5.2.3. Benefit #3 — Load Following

5.2.3.1. Description

Ideally market based pricing exists for this service. For this guide, however, generic generation costs are used as proxies for market-based prices. Generation cost has two possible elements: 1) marginal cost and 2) capacity cost, described below.

Generation marginal cost consists mostly of cost for fuel and for variable maintenance. The marginal cost can be *avoided* if generation does not have to operate to provide load-following service (because storage is used instead). Generation marginal cost may be *reduced* if part load operation (of generation for load following) is reduced. (Avoiding part load operation is important because doing so reduces generation wear, fuel use and air emissions per kWh delivered.)

Generation capacity-related cost involves cost incurred to add generation capacity The need for additional generation capacity for load following is quite region-specific and year-specific, ranging from no extra load following capacity needed to a need for relatively large increments. Similarly, the type of generation preferred for new load following capacity is region-specific. That preference depends on, among other factors, the mix of existing generation, load characteristics, and regional generation fuel preferences. The type of load following capacity added ranges from hydroelectric generation capacity to simple cycle and combined cycle generation capacity.

5.2.3.2. Estimate

At the low end, the unit price for load following *service* may be based on the marginal cost for low-cost hydroelectric generation. So, the assumed low value is $20/MW per service hour. At the high end, the unit price for load following service reflects the marginal cost for combined cycle generation. Therefore, the assumed high value is $50/MW per hour of service.

The *capacity*-related benefit is estimated based on the generation capacity cost assumed for the electric supply capacity benefit (See Section 5.2.2). At the low end is a relatively clean, simple cycle combustion turbine costing $60/kW year to own or rent. At the high end of the spectrum is a new, combined cycle plant whose annual cost of $120/kW-year.

Values in Table 13 show annual and 10-year lifecycle cost calculations for generation-based load following. The table includes service-related costs and capacity-related costs. Service costs reflect a low price of $20/MW per hour, a midrange price of $35/MW per hour of service, and a high price of $50/MW per hour. Annual capacity costs include a low value of $60/kW-year and a high value of $120/kW-year. Three scenarios shown include 500, 1,000, and 2,000 hours per year of load following service.

Table 13. Load Following Benefit Calculations

		500 Hrs./Year		1,000 Hrs./Year		2,000 Hrs./Year	
		Annual ($/kW-yr)	Ten Year ($/kW)	Annual ($/kW-yr)	Ten Year ($/kW)	Annual ($/kW-yr)	Ten Year ($/kW)
Service	$20.0/MW per hour	10.0	71.7	20.0	143.4	40.0	286.8
	$35.0/MW per hour	17.5	125.5	35.0	251.0	70.0	501.9
	$50.0/MW per hour	25.0	179.3	50.0	358.5	100.0	717.0
		Annual ($/kW-yr)	Ten Year ($/kW)				
Capacity	$60/kW-year	60	430.2				
	$120/kW-year	120	860.4				

Assuming 2,000 service hours per year and an average unit price of $30/MW per hour of service, the marginal cost is about $430/kW. Assuming that at least some capacity cost will also be incurred over 10 years, a generic load following benefit value of $800/kW is used in this guide.

5.2.4. Benefit #4 — Area Regulation

5.2.4.1. Description

At minimum, and until regulation requirements change, the internalizable benefit from storage used for area regulation will be the same amount (per kW per hour of service) as conventional generation-based regulation, with the value reflecting the prevailing price paid for the service. That price is denominated in $/MW per hour of *service*. Nonetheless, as described in Section 3.3.2 and in Appendix E, two important features may make storage the superior area regulation resource.

First, most types of storage can respond somewhat-to-very rapidly (*i.e.*, the rate of discharging and charging can change rapidly). Flywheels, capacitors, SMES, and many types of batteries have such a fast response. Even generation-like pumped hydroelectric storage and CAES can respond more quickly than many generation-based regulation resources. Because of this characteristic, regulation from such rapid-response storage may provide up to twice the benefit as regulation from generation.[43][44][45]

Second, unlike *generation* used for area regulation, *efficient* storage can provide 2 kW of service for each 1 kW of rated output. Storage can do that because it can provide regulation while discharging *and* while charging, in a fashion similar to storage used for load following.

Notably, if providing area regulation while *charging*, energy that is lost (as a function of storage efficiency) must be purchased at the prevailing price. Consider an example: 10 MW of 90% efficient storage used for area regulation; during a specific hour when storage provides regulation, it *absorbs* 4 MWh to provide down regulation, and it *injects* 4 MWh to provide up regulation. In that example, the energy losses for the hour are calculated as

$$(1 - 0.9) \times 4 \text{ MWh} = 0.40 \text{ MWh}.$$

> The price for area regulation – denominated in $/MW per hour of service – is not the same as the price for energy which is denominated in $/MWh. Rather, the price for area regulation reflects payment for one hour of service for each MW, without regard to the amount of energy involved.
>
> Although unlikely, area regulation resources could be made available during a given hour to provide regulation service without actually being used to provide the service. In that case, area regulation providers would receive a payment for one hour of service, with no energy-related implications.

5.2.4.2. Estimate

Revenue for providing up and down regulation services (regulation) for one year was estimated based on the California Independent System Operator's (CAISO's) published hourly prices for 2006. Those prices (in $/MW per hour of *service*) for up and for down regulation, are presented in Appendix E.

In 2006, in California the combined price (for up *and* down regulation) averaged about $36.70/MW per service hour (based on an annual average of $21.48/MW per service hour for up regulation and $15.33/MW per service hour for down regulation). After escalating the value for two years (at 2.5%), the price assumed is an hourly average of $38.55/MW per service hour.

Further, two storage operating scenarios for area regulation are evaluated: 1) operation 50% of the year and 2) operation 80% of the year. The single-year and 10-year lifecycle benefits for those prices and operating scenarios are shown in Table 14. The standard value for the area regulation benefit is $785/kW to $2,010/kW, for an average of $1,397/kW.

As noted above, it is possible that storage with rapid response may provide area regulation service whose benefit is twice that of the slower, generation-based regulation. If so, the benefit would be roughly double the values in Table 14.

Table 14. Area Regulation Annual and Lifecycle Benefit Summary

	Low		High	
Capacity Factor	0.50		0.80	
Annual Service Hours	4,380		7,008	
Regulation Price* ($/MW per service hour)	25.0	40.0	25.0	40.0
Annual Benefit ($/kW)	110	175	175	280
Lifecycle Value** ($/kW)	785	1,256	1,256	2,010

* For up regulation *plus* down regulation.
** For ten years, assuming PW factor = 7.17

5.2.5. Benefit #5 — Electric Supply Reserve Capacity

5.2.5.1. Description

Storage serving as electric supply reserve capacity (reserves) reduces the need and cost for those reserves that are normally supplied by generation. In many cases, the price for reserves is market-based – typically prices are a result of 'day-ahead' and 'hour-ahead' bidding.

The electric supply reserve capacity benefit is somewhat small – because generation-based reserves are inexpensive; nonetheless, it could be an important element of an attractive value proposition because providing reserves has low incremental cost. While charging, storage can provide two times its capacity as reserves (it can simultaneously cease charging and begin discharging). When charged storage can, in most cases, provide reserves merely by being ready to discharge (reserves are only used infrequently).

5.2.5.2. Estimate

The electric supply reserve capacity benefit estimate is based on the price paid for reserves and the number of hours per year during which storage provides reserves. Benefits are estimated assuming a low price of $3/MW per service hour and a high of $6/MW per service hour. Storage is assumed to provide 2,628 service hours per year at the low end and 5,256 service hours per year at the high end. The resulting annual benefit for those two scenarios is shown in Table 15.

Table 15. Electric Supply Reserve Capacity Annual Benefit

	Low	High
Capacity Factor	0.30	0.60
Annual Service Hours	2,628	5,256
Charge ($/MW per service hour)	3.0	6.0
Annual Value ($/kW-year)	7.9	31.5
Lifecycle Value* ($/kW)	57	226

*10 years, PW factor = 7.17

5.2.6. Benefit #6 — Voltage Support

5.2.6.1. Description

Voltage support provided by storage offsets the need to use large/central generation to provide reactive power to the grid when region-wide voltage emergencies occur. Competing alternatives (to storage) may include a) do nothing and endure the cost of additional outages or the risk associated with possible outages; b) buy insurance to cover possible liabilities; c) perform load management (primarily via curtailable/interruptible loads and possibly direct load control); d) incur a forced outage; and e) add central generation capacity to provide voltage support.

5.2.6.2. Estimate

Establishing a generic benefit estimate for the voltage support application requires use of generalizations and simplifying assumptions. In general, benefit estimates should account for the limited likelihood of such an outage that may occur in any given area and the degree to which storage contributes to avoiding such an event. Furthermore, unless the utility is financially responsible for outage-related costs, it has no significant direct incentive to pay for or even to coordinate distributed resources for voltage support.

The approach used to estimate the voltage support benefit is similar to that used to estimate the benefit of storage for electric service reliability. The general concept involves segmenting the utility customer base into three groups: 1) those ascribing little or no value to avoiding outages, 2) end users for whom outages are somewhat costly, and 3) end users for whom avoiding outages has a high value. That yields a composite value for avoiding an outage of 1 kW for one hour.

The next step is to establish an assumption about how long outages may last. Finally, an assumption is needed about how many outages will be avoided over the 10-year life of the storage. These two criteria are not easy to generalize.

For the benefit estimate in this report, it is assumed that at the low end the distributed voltage support resources (including storage) would prevent one outage lasting one hour over 10 years. At the high end, distributed voltage support resources (including storage) are assumed to prevent one outage lasting two hours during its 10-year life.

The unit value assumed for this estimate is $20 per hour of unserved load. For an outage lasting one hour, that's $20/kW lifecycle (without regard to time value of money) for each kW of *system peak load*. For an outage lasting two hours, that's two hours at $20/kW or $40/kW, lifecycle (without regard to the time value of money).

The standard assumption value for market potential is based on the premise that combined voltage support resources are distributed, are located where they can provide good support, and have an aggregate rating equal to 5% of peak load. Thus, by using *distributed* storage whose power is rated at 5% of peak load to avoid a 1-hour outage, the benefit is

$\$20/\text{kW}_{\text{load}} \div 0.05 = \$400/\text{kW}$ of distributed storage.

Avoiding a single *2-hour* outage over 10 years is worth

$\$40/\text{kW}_{\text{load}} \div 0.05 = \$800/\text{kW}$ of distributed storage.

5.2.7. Benefit #7 — Transmission Support

5.2.7.1. Description

To the extent that storage increases the load carrying capacity of the transmission system, a non-trivial benefit may accrue if transmission outages are avoided. Such a benefit may also accrue if additional load carrying capacity defers the need to add more transmission capacity and/or additional T&D equipment, and/or if it is rented to participants in the wholesale electric marketplace (to transmit energy) for revenue.

5.2.7.2. Estimate

When evaluating the merits of using storage for transmission support, the upper bound of the benefit value is the cost for the standard utility solution. For example, if capacitors are the proposed standard solution, then energy storage would offset the need (and cost) for those capacitors. The avoided cost (of the capacitors) is the resulting storage benefit for the transmission support application.[46]

The financial benefit values listed in Table 16 are estimated based on related research by EPRI. That research addressed SMES used for T&D support needs in Southern California during hot summer conditions when the need is greatest and when the benefits are highest. The estimates are based on conservative assumptions.[47][48] Based on those values, the standard lifecycle benefit value assumed for transmission support is $192/kW.[49][50][51]

Table 16. Transmission Support Annual Financial Benefit

Benefit Type	Annual Benefit ($/kW-year)	Lifecycle Benefit ($PV/kW)[#]
Transmission Enhancement	15.1	108
Voltage Control ($ capital*)	n/a	29
Subsynchronous Resonance (SSR) Damping ($ capital*)	n/a	16
Underfrequency load-shedding (per occurrence)	12.8	38**
Total		**192**

Notes:
1. All value are for Southern California, assuming hot summer conditions, circumstances for which benefits are highest.

2. Based on values established in 2003 and escalated at 2.5% for six years.

*The benefit is the cost of the most likely alternative (e.g., capacitors), that would have been incurred if storage was not deployed.

**$12.8/kW, per occurrence. Assume three occurrences over the (ten year) life of the unit. This value has not been adjusted to account for time value of money.

#Based on a PV Factor of 7.17 and a ten year life.

5.2.8. Benefit #8 — Transmission Congestion Relief

5.2.8.1. Description

Alternatives that may compete with storage for transmission congestion relief include a) dumping energy upstream from congestion, b) providing load management and energy efficiency downstream from congestion, c) paying congestion charges, and d) adding transmission capacity. Note that for this application, if the generation (upstream from congestion) is already installed, then the do nothing option is the same as the dump energy option.

Given the possible shortfall of transmission capacity within and into many regions, congestion charges are possible if not likely. Currently, however, these charges cannot be generalized well – primarily because the marketplace within which transmission congestion charges will apply is in the formative stages and because congestion charges will be location-specific.

Much, if not most, of the new congestion will probably occur as more renewables (deployed in response to Renewables Portfolio Standard [RPS] targets) compete for the existing transmission capacity. Furthermore, it is assumed that the do nothing and the dump energy options are not likely. So, for this application, the benefit is based on transmission congestion charges at the low end and the cost of a transmission upgrade at the high end.

5.2.8.2. *Estimate*

Transmission congestion charges are becoming more common. In the parts of California's transmission system where it occurs, congestion is present for 10% to 17% of all hours during the year. Congestion charges in those areas range from about $5/MW per service hour to about $15/MW per service hour.[52] As shown in Table 17, that yields an annual benefit whose average value is on the order of $12/kW-year and a lifecycle benefit averaging about $86/kW. Although that is a small amount compared to the cost for storage, it could be an element of a value proposition that includes several benefits.

Table 17. Congestion Charges in California, $2007

	Low	High
Portion of Year	10%	15%
Hours Per Year	876	1,314
Transmission Access Charge ($/MW per hour of service)	5	15
Annual Cost ($/kW-year)	4.38	19.71
Lifecycle Value* ($/kW)	31	141

*10 years, PW factor = 7.17

Source: derived based on data from CAISO.

More compelling are transmission corridors requiring an upgrade due to congestion. In those cases, the benefit is the cost that can be avoided by deferring or avoiding the upgrade. The cost of a transmission upgrade varies significantly depending on distance, permitting and siting challenges, and the equipment's rating.

5.2.9. Benefit #9 — Transmission and Distribution Upgrade Deferral

5.2.9.1. *Description*

The *single-year* T&D upgrade deferral benefit (deferral benefit) is the financial value associated with deferring a utility T&D upgrade for one year. That value reflects the utility's financial carrying charge for the new equipment involved in the upgrade. Carrying charges include the costs for financing, taxes, and insurance incurred for one year of ownership of the equipment used for the upgrade. For a utility, that amount is also known as the 'revenue requirement.'

The carrying charge (revenue requirement) *for one year* is estimated by multiplying the utility fixed charge rate times the total installed cost for the upgrade. Consider, for example, a distribution upgrade costing $1 million to purchase and install. If the utility fixed charge rate is 0.11, then the annual revenue requirement – and thus the *single year* deferral benefit – is

$\$1 \text{ million} \times 0.11 = \$110{,}000.$

Note that, for this guide, T&D operating cost avoided, if any, is assumed to be negligible. Also note that, by definition, reducing the utility revenue requirement reduces the utility's total cost-of-service paid by all customers as a group.

Storage power indicates the amount of storage needed for one year of deferral. It is expressed as a percentage of the existing T&D equipment nameplate rating (the equipment to be upgraded). An example: If T&D equipment to be upgraded is rated at 12 MVA, then 3% storage power is

$$3\% \times 12 \text{ MVA} = 0.36 \text{ MVA or } 360 \text{ kVA.}$$

The assumed 3% storage power is intended to be representative. In practice, that value can fall within a range of as little as 1% to as much as 10%, depending on the actual peak load in the previous year plus load shape; expected load growth; load growth uncertainty; storage module sizes available; engineering philosophy and preferences, especially regarding storage oversizing to account for uncertainty; and possibly other criteria.

For more details about storage sizing for T&D upgrade deferral, readers are encouraged to refer to a report published by Sandia National Laboratories entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program*.[53] Also, refer to the discussion addressing use of *modular* storage for reducing T&D investment risk in Section 5.3.

5.2.9.2. Estimate

The starting point for estimating the T&D upgrade deferral benefit is to establish the cost of the T&D upgrade to be deferred. The data used as the basis for establishing that cost is expressed in dollars per kW added – the T&D marginal cost. In California, for 50% of all locations requiring an upgrade in any given year, the *marginal* cost is $420/kW or more (*i.e.*, $420/kW *added*). For the most expensive locations requiring upgrades (90th percentile and above), the upgrade cost exceeds about $662 per kW of capacity *added*.[54][55]

As an aside, a familiar criterion for T&D planners is $/kVA *installed*. To estimate that value based on the *marginal* cost, an upgrade factor is used. The upgrade factor is the ratio of the capacity *added* to the existing capacity. Consider an example: If 4 MVA of capacity is added to a 12 MVA system, the upgrade factor is 0.34. Typical values for upgrade factor range from 0.25 to 0.50. An upgrade factor of 0.33 is assumed for this guide.

The T&D cost estimates used to estimate the T&D upgrade deferral benefit are summarized in the two tables below. Values in Table 18 indicate the single-year deferral benefit for locations whose cost is among the highest 50% of all costs for all upgrades needed. The value used, $684/kVA of storage for one year, reflects the 0.33 T&D upgrade factor, 0.11 fixed charge rate, and 3% storage power as described above.

Table 18. T&D Upgrade Cost and Benefit Summary, 50th Percentile

Upgrade Scenario Final Rating (MVA)	Capacity Added (MVA)	Upgrade Factor	Upgrade Installed Cost* $/kVA**	Upgrade Installed Cost* $	Upgrade Annual Cost*** ($)	Storage 1 Year Benefit# ($/kVA-year)
15	3	0.25	105.0	1,575,000	173,250	481
16	4	0.33	140.0	2,240,000	246,400	684
18	6	0.50	210.0	3,780,000	415,800	1,155

*If marginal cost per kVA of T&D capacity $/kVA added is $420/kVA.
**Per kVA *installed* .
*** $Upgrade Installed Cost * 0.110 Fixed Charge Rate
# $Upgrade Annual Cost ÷ 360 kVA. (Based on 3.0% storage power)

The annual upgrade deferral value is $1,079/kVA of storage for one year for upgrades whose cost is among the highest 10% of upgrades needed, based on values shown in Table 19.

Table 19. T&D Upgrade Cost and Benefit Summary, 90th Percentile

Upgrade Scenario Final Rating (MVA)	Capacity Added (MVA)	Upgrade Factor	Upgrade Installed Cost* $/kVA**	Upgrade Installed Cost* $	Upgrade Annual Cost*** ($)	Storage 1 Year Benefit# ($/kVA-year)
15	3	0.25	165.5	2,482,500	273,075	759
16	4	0.33	220.7	3,530,667	388,373	1,079
18	6	0.50	331.0	5,958,000	655,380	1,821

*If marginal cost per kVA of T&D capacity $/kVA added is $662/kVA.
**Per kVA *installed* .
*** $Upgrade Installed Cost * 0.110 Fixed Charge Rate
# $Upgrade Annual Cost ÷ 360 kVA. (Based on 3.0% storage power)

Consider this important note: The assessment described above must occur *each year* for a given deferral because, normally, the amount of load served by a given T&D node grows. So, in each year after a deferral, power engineers must reassess the merits of using storage for another year of deferral. Usually, load grows such that for each subsequent year the amount of storage needed to keep pace with load growth, and thus the amount needed to defer an upgrade for the next year, nearly doubles. In some cases, the discharge duration requirements increase too.

5.2.10. Benefit #10 — Substation On-site Power

5.2.10.1. Description

Battery storage systems (mostly lead-acid batteries) provide power at electric utility substations for switching components and for substation communication and control equipment when the grid is not energized.[56]

5.2.10.2. Estimate

Establishing a benefit value for substation on-site power is challenging. Certainly, battery systems provide critical service because the grid would be much more vulnerable to outages, and perhaps even equipment damage without an on-site, non-grid power source for times when the grid is not operational. The benefit for this application is estimated based on the price for high quality UPS systems (like those shown in Table 24 of Section 5.2.13.4).

The cost of such a state-of-the-art lead-acid battery-based system, with eight hours of discharge duration, is based on a price of $225/kW for power and $200/kWh of discharge.[57] Therefore, the presumed system (equipment) price is

$$\$225/\text{kW} + (8 \text{ hours} \times \$200/\text{kWh})$$

$$= \$225/\text{kW} + \$1{,}600/\text{kW}$$

$$= \$1{,}825/\text{kW}.$$

Similarly, the presumed price for a system with 16 hours of discharge duration is

$$\$225/\text{kW} + (16 \text{ hours} \times \$200/\text{kWh})$$

$$= \$225/\text{kW} + \$3{,}200/\text{kW}$$

$$= \$3{,}425/\text{kW}.$$

Given the limited discharge of these systems, variable operating costs are ignored.

5.2.11. Benefit #11 — Time-of-use Energy Cost Management

5.2.11.1. Description

To reduce electricity end users' time-of-use (TOU) energy cost, storage is charged with low-priced energy so that the stored energy can be used later when energy prices are high. The resulting overall electric energy cost reduction is the benefit associated with use of storage for TOU energy cost management.

TOU energy prices are specified by the applicable rate structure (tariff). Typically, those prices vary by time of day, day of the week, and season of the year. There may be two or more price points for specific days. The standard assumption value for this benefit is calculated based on PG&E's A-6 Small General TOU Service tariff. Commercial and industrial (C&I) electricity end users whose power requirements are greater than 199 kW and less than or equal to 500 kW are eligible for the A-6 tariff. TOU electricity prices for the A-6 tariff are shown in Table 20.

The summer billing period extends from May through October, and the winter billing period is November through April. Summer on-peak hours are 12:00 p.m. to 6:00 p.m. (Monday-Friday, except holidays); partial-peak hours are 8:30 a.m. to 12:00 p.m. and 6:00 p.m. to 9:30 p.m. (Monday-Friday, except holidays); and off-peak hours are 9:30 p.m. to 8:30 a.m. (Monday-Friday; all day Saturday, Sunday, and holidays). There is no winter on-peak period. Partial peak hours are 8:30 a.m. to 9:30 p.m. (Monday-Friday, except holidays); and off-peak hours are 9:30 p.m. to 8:30 a.m. (Monday-Friday; all day Saturday, Sunday, and holidays). PG&E tariffs are available at http://www.pge.com/tariffs.

Table 20. PG&E A-6 Time-of-use Energy Price Tariff

Period	Total	Generation	%	Distribution	%
Peak Summer	$0.37	$0.21	57.0%	$0.13	34.9%
Part-Peak Summer	$0.17	$0.09	53.0%	$0.05	29.8%
Off-Peak Summer	$0.11	$0.06	49.9%	$0.03	23.3%
Part-Peak Winter	$0.13	$0.06	46.0%	$0.04	31.8%
Off-Peak Winter	$0.11	$0.05	47.4%	$0.03	25.7%

Transmisison: $0.00913 for all hours.

5.2.11.2. Estimate

The A-6 tariff's on-peak energy price applies to 720 hours per year. Storage with a 6-hour discharge duration would allow the end user to avoid annual on-peak energy charges of

37¢/kWh × 720 hours/year

= $0.37/kWh × 720 hours/year

= $266/kW-year.

To charge an 80% efficient energy storage system, it is necessary to use 1.25 kWh of energy in to get one kWh out. Consider a 1-MW storage plant: To discharge for 720 hours (720MWh), the storage would have to be charged with

720 × 1.25 = 900MWh.

So, the charging energy cost using low-priced, off-peak energy priced at 11¢/kWh is

$0.11/kWh × 900 hours/year = $99/kW-year.

The cost *reduction* realized is

$266/kW-year – $99/kW-year = $167/kW-year.

To express that annual (cost reduction) benefit in units of $/kW lifecycle, the annual cost is multiplied by the PW factor of 7.17

$167/kW-year × 7.17 = $1,198/kW.

The storage plant could have a discharge duration that is less than the duration of the 6- hour, on-peak price period specified in the tariff. If, for example, two hours of backup are needed from a storage system with four hours of discharge, then the remaining two hours of discharge could be used for reducing energy cost. The lifecycle benefit is

(2 hours ÷ 6 hours) × $1,198/kW-year

= 0.33 × $1,198/kW-year

= $395/kW.

Note that the benefit estimate illustrated above does not account for variable maintenance costs incurred as the storage plant is used (*e.g.*, overhauls and subsystem replacement, as applicable).

5.2.12. Benefit #12 — Demand Charge Management

5.2.12.1. Description

Demand charge management involves storage used to reduce an electricity end user's *power* draw on the electric grid during times when electricity use is high (*i.e.,* during peak electric demand periods). To reduce or avoid demand charges, storage is charged when low or no demand charges apply, presumably using low-priced energy. The storage is later discharged when demand charges apply. The benefit value is the overall reduction in cost due to reduced or avoided demand charges.

To one extent or another, demand charges reflect the cost for utility *equipment* needed to generate, transmit, and distribute electric energy. So, demand charges are denominated in $/kW of power draw because that criterion defines the *capacity* that the electricity *infrastructure* must have to deliver service to the customer. In most cases, the demand charge is assessed each month based on the maximum power draw within the respective month. It is important to note that tariffs with demand charges also have separate prices for energy, denominated in ¢/kWh.

Demand charges and, in most cases, energy prices are specified by the end user's electricity rate structure (tariff). Typically, demand charges vary by day of the week and by season. Demand charges may also vary by time of day.

Demand charges are assessed *each month* based on the maximum load that occurs during times when peak demand charges apply, normally 1) peak, 2) partial-peak, and 3) off-peak. Some tariffs with demand charges also include what could be called an 'anytime' demand charge. Known generically as a 'facility' demand charge, these charges are levied based on the peak demand no matter when it occurs (time or season). That is important for storage because most storage charging occurs at night when demand from utility customers' non-storage loads tends to be low. In those circumstances, charging storage at night will increase the anytime or facility demand charges incurred. Note that off-peak demand charges have a similar effect though the charges are based on maximum off-peak demand during the respective month.

The standard assumption value for this benefit is calculated based on PG&E's E-19 Medium General Demand-Metered TOU Service tariff. That tariff applies to commercial and industrial (C&I) end users with peak demand that exceeds 500 kW. PG&E tariffs are available at http://www.pge.com/tariffs.

The E-19 tariff has three monthly demand charges during six 'summer' months (May through October). Summer on-peak hours are 12:00 p.m. to 6:00 p.m. (Monday-Friday, except holidays); partial-peak hours are 8:30 a.m. to 12:00 p.m. and 6:00 p.m. to 9:30 p.m. (Monday-Friday, except holidays); and off-peak hours are 9:30 p.m. to 8:30 a.m. (Monday-Friday; all day Saturday, Sunday, and holidays). (Notably, the off-peak demand charges will apply during charging.)

During the six 'winter' months (November through April), there are only two monthly demand periods: partial-peak and off-peak. Partial peak hours are 8:30 a.m. to 9:30 p.m. (Monday-Friday, except holidays); and off-peak hours are 9:30 p.m. to 8:30 a.m. (Monday-Friday; all day Saturday, Sunday, and holidays). (As with storage use during summer months, the off-peak demand charges will apply during charging.)

Importantly, like most other tariffs with demand charges, the E-19 *energy* price (¢/kWh) paid by utility customers also depends on those time periods.

5.2.12.2. Estimate

The assumed electricity bill for a typical commercial end user using the E-19 tariff is shown in Table 21. The same end user's electric bill, after considering 80% efficient storage with 6 hours of discharge duration to eliminate peak load, is shown in Table 22. The changes due to use of storage are summarized in Table 23.

Table 21. Electricity Bill, E-19 Tariff, without Storage

Summer	Hours Per Year*	Demand Charge ($/kW-month)	Peak Load Factor	Demand Charges ($/kW-year)	Average Load Factor	Energy Use (kWh/year)	Energy Price ($/kWh)	Energy Charges ($/kW-year)	Total Charges ($/kW-year)
Peak	765	11.59	0.90	62.59	0.80	612	13.458	82.36	144.95
Partial-peak	893	2.65	0.80	12.72	0.60	536	9.257	49.57	62.29
Off-peak	2,723	6.89	0.60	24.80	0.55	1,497	7.541	112.92	137.72
Winter									
Partial-Peak	1,658	1.00	0.80	4.80	0.70	1,160	8.256	95.79	100.59
Off-Peak	2,723	6.89	0.55	22.74	0.50	1,361	7.286	99.18	121.92
			Total	**127.65**	**0.590**	**5,166**	**8.513**	**439.82**	**567.47**

*Approximate values.

**Average peak load during all months of the season.

Table 22. Electricity Bill, E-19 Tariff, with Storage

Summer	Hours Per Year*	Demand Charge ($/kW-month)	Peak Load Factor**	Demand Charges ($/kW-year)	Average Load Factor	Energy Use (kWh/year)	Energy Price (¢/kWh)	Energy Charges ($/kW-year)	Total Charges ($/kW-year)
Peak	765	11.59					13.458		
Partial-peak	893	2.65	0.80	12.72	0.60	536	9.257	49.57	62.29
Off-peak	2,723	6.89	0.80	33.07	0.82	2,232	7.541	168.35	201.42
Winter									
Partial-Peak	1,658	1.00	0.80	4.80	0.70	1,160	8.256	95.79	100.59
Off-Peak	2,723	6.89	0.55	22.74	0.50	1,361	7.286	99.18	121.92
			Total	**73.33**	**0.604**	**5,289**	**7.806**	**412.89**	**486.22**

*Approximate values.

**Average peak load during all months of the season.

1. Storage Efficiency: 80.0%.

Table 23. Electricity Bill Comparison, E-19 Tariff, with and without Storage

	Demand Charges ($/kW-year)	Average Load Factor	Energy Use (kWh/year)	Energy Price (¢/kWh)	Energy Charges ($/kW-year)	Total Charges ($/kW-year)
With Storage ($)	73.3	0.60	5,289	7.81	412.9	486.2
w/o Storage ($)	127.6	0.590	5,166	8.51	439.8	567.5
Change, w/Storage ($)	**-54.3**	**+0.014**	**+123***	**-0.71**	**-26.9**	**-81.2**
(%)	**-42.6%**	**2.4%**	**2.4%**	**-8.3%**	**-6.1%**	**-14.3%**

*Increase due to storage losses.

As shown in Table 23, *demand* charges are reduced by nearly 43% ($54.30), energy charges are reduced by a more modest 6.1% ($26.90), and the total annual bill is reduced by $81.20 for a total reduction of 14.3%.

5.2.13. Benefit #13 — Electric Service Reliability

5.2.13.1. Description

In simplest terms, the benefits associated with improved electric service reliability accrue if storage reduces financial losses associated with power outages. This benefit is highly end user-specific, and it applies to C&I customers, primarily those for whom power outages cause moderate to significant losses. If the utility has followed standard practices, it is usually the end user that is responsible for covering financial damages. In some cases, utilities are required to reimburse end users for financial losses due to outages.

5.2.13.2. Estimating End-user Reliability Benefit – Value-of-service Approach

For the value-of-service (VOS) approach, the benefit associated with increased electric service reliability is estimated using two criteria: 1) annual outage hours (*i.e.,* the number of hours per year during which outages occur) and 2) the value of ‘unserved energy’ or VOS. VOS is measured in $/kWh. The standard assumption value for annual outage hours is 2.5 hours per year. A VOS of $20/kWh is recommended as a placeholder.[58] To calculate the annual reliability benefit, the standard assumption value for annual outage hours is multiplied by the VOS:

$20/kWh × 2.5 hours per year = $50/kW-year.

To calculate lifecycle benefits over 10 years, the annual reliability benefit of $50/kW-year is multiplied by the PW factor (7.17):

$50/kW-year × 7.17 = $359/kW.

5.2.13.3. Estimating End-user Reliability Benefit – Per Event Approach

Reliability benefits may be estimated by ascribing a monetary cost to losses associated with power system events lasting one minute or more and that cause electric loads to go offline.[59] Reliability events considered are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to electric service reliability, a generic value of $10 per event for each kW of end user peak load is used.[60][61][62] The generic assumption for the annual number of events is 5.[63] The result is that storage used in such a way that the end user can avoid 5 electric reliability events, each worth $10 for each kW of end user peak load, yields an annual value of $50/kW-year.[64] Finally, multiplying by the PW factor of 7.17 yields a lifecycle benefit of $359/kW.

For additional information about financial considerations related to utility service reliability, please refer to a report produced by Lawrence Berkeley National Laboratory, *Evaluating the Cost of Power Interruptions and Power Quality to U.S. Electricity Consumers*.[65]

5.2.13.4. Estimating End-user Reliability Benefit – UPS Price Approach

One other possibly helpful proxy to use when estimating this benefit is the price paid for UPSs. Prices for a selection of commercially available UPSs are shown in Table 24.

Table 24. Commercially Available UPS Ratings and Prices

	Specifications				Price		
Item	True Power (Watts)	Apparent Power (Volt-Amps)	Power Factor	Discharge Duration* (Minutes)	Retail Price**	$/kW	$/kW-hour
APC Back-UPS ES 8 Outlet	200	350	0.57	2.3	44	220	5,739
Tripp Lite SMART550USB	300	550	0.55	5.3	225	748	8,472
Tripp Lite SMART1200XLHG	750	1,000	0.75	6.0	562	749	7,493
APC Back-UPS RS 1500VA	865	1,500	0.58	5.3	250	289	3,272
MGE Pulsar EX RT 3200VA	2,080	3,200	0.65	6.0	1,164	560	5,596
Tripp Lite SmartOnLine SU7500RT3U	6,000	7,500	0.80	9.0	3,493	582	3,881
Tripp Lite SmartOnLine SU10KRT3UHV	8,000	10,000	0.80	4.0	4,017	502	7,531
MGE Galaxy 30kVA	24,000	30,000	0.80	11.0	17,010	709	3,866
APC - Smart-UPS VT 30KVA 5 Batteries	24,000	30,000	0.80	13.7	19,410	809	3,542
		Average Power Factor	**0.699**		**Average**	**574.2**	**5,487.9**

*At full rated output.

**Based on an informal survey of retail prices.

Note: Assuming 5 year life, a rough approximation of annual cost ($/kW-year) is total cost ÷ 5.

Additional Notes:

1. Content in Table 24 does not constitute an endorsement or recommendation of the listed products or brands.
2. Power ratings are in units of volt-Amps (VA).
3. Typically 1.2 to 1.3 volt-Amps are required for each Watt of load.

As shown in Table 25, a rough estimate of the 10-year lifecycle benefit is $978/kW. This estimate assumes a 5-year UPS life and one replacement of the UPS over 10 years. It is based on a 2.5%/year price escalation and 10% discount rate.

Table 25. UPS Lifecycle Cost

Year	1	2	3	4	5	6	7	8	9	10	Total
Escalator	1.00	1.03	1.05	1.08	1.10	1.13	1.16	1.19	1.22	1.25	
Cost ($Year 1)	574.2	0	0	0	0	574.2	0	0	0	0	1,148
Escalated Cost ($Current)	574.2	0	0	0	0	649.7	0	0	0	0	
Discount Factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	
Present Value ($)	574.2	0	0	0	0	403.4	0	0	0	0	978

5.2.14. Benefit #14 — Electric Service Power Quality

5.2.14.1. Description

The electric service power quality benefit is highly end-user-specific and, as such, is difficult to generalize. It applies primarily to those C&I customers for whom power outages may cause moderate to significant losses.

Though power quality-related technical details are not covered in depth here, they *are* summarized in Section 3.5.4. Specific types of poor power quality are well characterized in many other reports and documents.[66]

In the most general terms, power-quality-related financial benefits accrue if energy storage reduces financial losses associated with power quality anomalies. Power quality anomalies of interest are those that cause loads to go offline and/or that damage electricity-using equipment and whose negative effects can be avoided if storage is used.

As an upper bound, the power quality benefit cannot exceed the cost to add the conventional solution. An example: If the annual power quality benefit (avoided financial loss) associated with an energy storage system is $100/kW-year, and basic power conditioning equipment costing $30/kW-year would solve the same problem if installed, then the maximum benefit that could be ascribed to the energy storage plant for improved power quality is $30/kW-year.

5.2.14.2. Estimate

Power quality-related benefits may be estimated by assigning a monetary value to losses associated with power quality events that last less than one minute and cause electric loads to go offline.[67] Power quality events considered are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to power quality, a generic value of $5 per event for each kW of end user peak load is the standard assumption value used in this guide. Based on that same information, the generic assumption for the annual number of events is 10.[68][69][70] The result is that storage used in such a way that the C&I electricity end user can avoid 10 power quality events per year, each worth $5 per kW of end user peak load, provides an annual benefit of $50/kW-year. After multiplying by the PW factor (7.17), the lifecycle electric service power quality benefit is $359/kW. Implicit in this approach is the assumption that the power quality benefit is the same for each of 10 years.

For additional coverage of this topic, please refer to a report published by Lawrence Berkeley National Laboratory entitled *Evaluating the Cost of Power Interruptions and Power Quality to U.S. Electricity Consumers*.[71]

5.2.15. Benefit #15 — Renewables Energy Time-shift

5.2.15.1. Description

For the renewables energy time-shift application, storage is charged with low-value electric energy generated using renewable energy. That energy is stored so that it may be used or sold at a later time when it is more valuable.

Two cases considered in this guide are time-shift of energy from wind generation and generic *baseload* renewable energy generation. (See Section 3.6.1 for details.)

5.2.15.2. End -user Time-of-use Energy Cost Reduction using Distributed Renewable Energy Generation

The renewables energy time-shift benefit is related to wholesale or 'spot market' electric energy for electricity supply. That is, the energy time-shift benefit described above is related to the avoided cost of purchasing electric energy from the wholesale or spot market.

An analogous opportunity exists for electricity end users to derive a renewables energy time-shift benefit. Specifically, if an end user's electric service tariff includes TOU energy prices, then the end user could use storage to time-shift energy to reduce cost for electric energy. (See Section 3.5.1 and Section 5.2.11 for more details.)

5.2.15.3. Incremental Benefit and Cost for Adding Storage for Renewables Energy Time-shift

Readers should note that the renewables energy time-shift benefit estimated in this guide accrues because it is *added* to renewable energy generation. That means that the benefit is *incremental*. Consequently, when evaluating the financial merits of adding storage to renewable energy generation, the incremental benefit is compared to incremental cost (to add storage); which means that the entire evaluation addresses the incremental benefit/cost relationship for storage.

> To one extent or another, the fuel-related cost for renewable energy is more predictable than fuel cost for conventional generation. In effect, renewable energy provides a 'hedge' against the possibility that fuel prices will be higher than expected.
>
> One simple way to quantify at least part of this effect is based on evaluations by the Lawrence Berkeley National Laboratory Electricity Market and Policy program. Based on recent work by that group, the 'forward prices' for fuel that reflect the terms of actual electricity purchase *contracts* are on the order of 10% or more higher than prices that are forecast.
>
> Indeed, a significant portion of electric energy from renewables is procured using firm prices, contracts, or power purchase agreements, rather than spot market prices. Consequently, the benefit estimated for renewables energy time-shift based on a forecast is likely to understate the energy-related benefit.[72]

5.2.15.4. Estimate

Although each region is different, forecast energy prices for California are used to estimate the renewables energy time-shift benefit. A summary of those prices are shown in Table 26. (See Appendix F for details about the electricity prices used.)

Table 26. Wholesale Spot Energy Price Differentials, On-peak and Off-peak, Weekdays, California Forecast for 2009 (in $/MWh)

Monthly Price "Bins"

Month=> Hour	1	2	3	4	5	6	7	8	9	10	11	12
12:00 P.M. - 5:00 P.M.	85.1	74.5	77.6	94.6	100.3	118.0	148.2	163.1	142.5	99.1	104.5	105.9
1:00 A.M. - 6:00 A.M.	-51.8	-44.4	-46.2	-61.2	-42.7	-35.2	-55.1	-69.7	-77.0	-61.3	-61.5	-72.9
Storage Losses*	-10.4	-8.9	-9.2	-12.2	-8.5	-7.0	-11.0	-13.9	-15.4	-12.3	-12.3	-14.6
Net Time-shift Benefit	23.0	21.1	22.1	21.1	49.1	75.7	82.1	79.4	50.1	25.5	30.7	18.4

Seasonal Price "Bins"

	May - October	November - April
12:00 P.M. - 5:00 P.M.	128.5	90.4
1:00 A.M. - 6:00 A.M.	-56.8	-56.4
Storage Losses*	-11.4	-11.3
Net Time-shift Benefit	60.3	22.8

Annual

	Hours	Value**
May - October	651.8	39,323
November - April	651.8	14,830
Total	1,304	54,152

**Net time-shift benefit * hours/year.

*Storage Efficiency = 80.0%.

Note: Values expressed in units of $/MWh.

Although not used directly for the estimate in this guide, the range of typical variable costs for electric energy from fossil-fueled generation are shown in Figure 18. The figure is provided as context for the prices shown in Table 26. Values reflect a) fuel efficiencies ranging from 35% to 55%, b) fuel prices ranging from $3/MMBtu to $9/MMBtu, and c) a generic value of 1 ¢/kWh for non fuel variable operation cost.

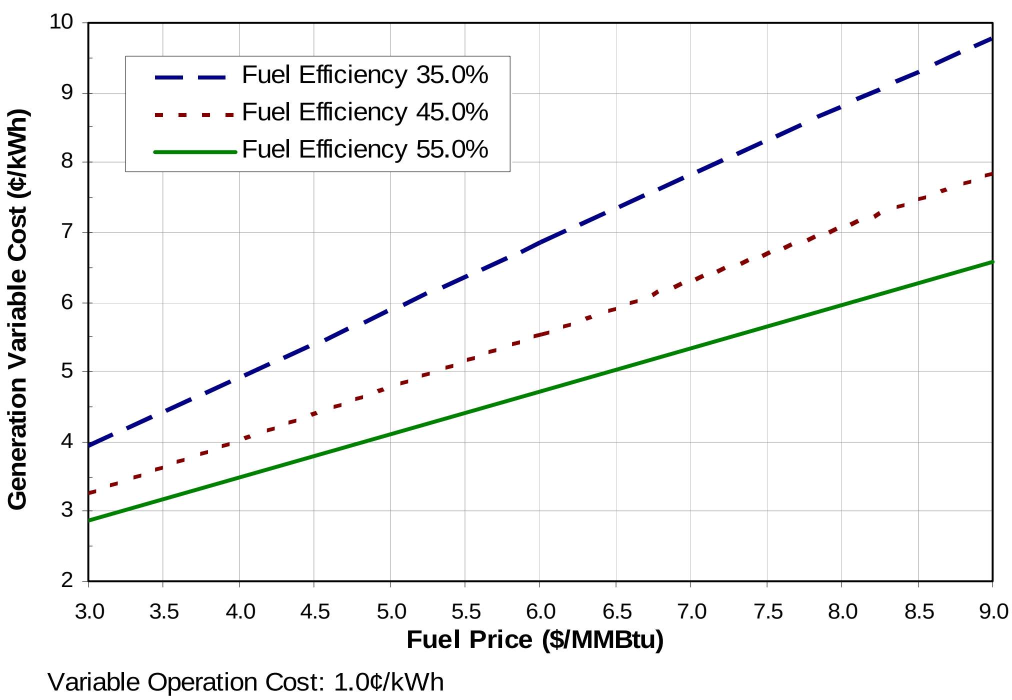


Figure 18. Generation variable cost, for various fuel prices and fuel efficiencies.

Based on the range of variable costs shown in Figure 18, variable cost for generation ranges from about 4.8 ¢/kWh for a 45% efficient combined cycle plant assuming fuel price of about $5/MMBtu to about 7 ¢/kWh for a 35% efficient simple cycle combustion turbine plant using higher priced ‘on peak’ fuel costing $6/MMBtu. The primary driver of those generic variable cost values is fuel price, shown on the graph’s X-axis. The variable cost values in Figure 18 also reflect a generic, non-fuel-related variable operation and maintenance (O&M) cost of 1¢ /kWh. Note that the O&M cost for simple cycle combustion turbine generation is about 2.5 ¢/kWh and for combined cycle generation (a common type of new generation) is on the order of 0.43 ¢/kWh.[73]

5.2.15.5. Wind Energy Time-shift

For the wind generation case, the energy time-shift benefit is estimated based on the assumed difference between the annual average wholesale/spot value for on-peak energy and off-peak energy, net of energy storage losses. Instead of selling off-peak energy in real-time (when generated), that energy is stored and used at a later time when energy prices are high.

The off-peak *versus* on-peak price differential is estimated based on the price differential between weekday energy prices occurring during the periods of a) 12:00 p.m. to 5:00 p.m. and b) 1:00 a.m. to 6:00 a.m., as shown in Table 26. Also shown in Table 26: Time-shifting for 5 *full* hours per day (5 kWh per day per kW of wind generation), for all weekdays during the year, is worth about $54,152/MW-year or about $54.2/kW-year. Nevertheless, Figure 8 (in Section 3.6.1.2) shows that at least some of the wind generation’s output occurs during the on-peak period when the energy is already most valuable. Consequently, the amount of energy from wind generation that is actually time-shifted is less than would be needed for 5 *full* hours of storage discharge (*i.e.*, is less than 5 kWh per kW of wind generation).

Depending on the applicable wind generation production profile(s), storage could be used to time-shift 2 to 4 kWh per day, per kW of wind generation. Assuming that storage can be used to time-shift 3 kWh per kW of wind generation during a 5-hour on-peak period, the energy time-shift benefit (based on the above values) is:

(3 kWh ÷ 5 hrs) × $54.2/kW-year = $32.5/kW-year.

When multiplied by the PW factor, the benefit over 10 years is

$32.5/kW-year × 7.17 = $233.2/kW.

Depending on the local and regional circumstances, there may be an electric supply capacity-related benefit if the time-shift involves storage discharging as shown in Figure 8. (Also see the renewables capacity firming benefit characterization in Section 5.2.16.)

> Importantly, to the extent that adding energy storage for energy time-shift increases output during times when peak demand occurs, a capacity credit may also apply.
>
> Based on the benefit estimate used for the electric supply capacity application, the 10-year capacity credit could range from nothing (if generation capacity is not needed) up to $864/kW ($120/kW-year), if the need for a natural-gas-fueled combined cycle generation plant is avoided.
>
> Based on those values, the benefit for energy time-shift plus supply capacity from *baseload* renewable energy generation ranges from $389/kW over 10 years (in areas not needing additional generation capacity) up to $1,288/kW if the time-shift defers the need for combined cycle power plant capacity.

5.2.15.6. Baseload Renewables Energy Time-shift

The energy time-shift benefit for baseload renewable energy generation is based on the value achieved by storing low-value energy during off-peak periods and discharging the storage on-peak. As shown in Figure 9 (Section 3.6.1.3), the effect is to avoid using or selling the generator's energy when that energy has a low value and to increase the amount of electric energy available during times when that energy is more valuable. Based on the differential between the price for off-peak energy and the price for on-peak energy (shown in Table 26), the value related to energy time-shift for baseload renewable energy generation is approximately \$54.2/kW-year or about \$389/kW over 10 years (7.17 × \$54.2/kW-year).

5.2.16. Benefit #16 — Renewables Capacity Firming

5.2.16.1. Description

The benefit for firming output from renewable energy generation is related to the cost that can be avoided for other electric *supply* capacity. If renewable energy generation output is constant during times when demand is high, then less conventional generation *capacity* is needed. In this guide, benefits are estimated for two cases: 1) distributed PV generation and 2) bulk wind generation. (See the benefit characterization in Section 3.6.2 for details.)

5.2.16.2. Capacity Credit

The value of a generator's capacity (capacity credit) is based on the degree to which the generator's capacity contributes to the reliability of the electric supply system, primarily during peak demand periods. It is also based on the cost for electric supply resources which may include local or regional generation plants, power purchases, or demand response. Capacity credit is an important criterion of merit used by power engineers to estimate the contribution that renewable energy-fueled generation makes toward the total amount of power required to serve load.

Perhaps the most robust way to estimate an intermittent generator's capacity credit is to calculate the effective load carrying capacity (ELCC). ELCC is a measure of a power plant's contribution to the greater electric supply system's capacity during times when the amount and reliability of capacity is important. ELCC is established using reliability and/or production cost models to estimate common reliability indices, such as loss of load probability, loss of load expectation, or expected unserved energy.

All power plants, except for the benchmark (a fully dispatchable, very reliable combustion turbine-based generator), have an ELCC that is less than the generator's rated capacity. For example, 100 MW of wind generation may have a capacity credit of 0.25; which means that the wind generation provides 0.25 × 100 MW = 25 MW of *capacity* to the electric supply system when demand is high.

5.2.16.3. Generation Capacity Cost

The cost assumed for generation capacity (which forms the basis for the capacity firming benefit) is the same as the generation cost for the electric supply capacity benefit, as described in Section 5.2.2. It is for a combustion-turbine-based generation plant whose annual cost is assumed to be \$120/kW-year.

5.2.16.4. On-peak Period and Storage Operation

Renewables capacity firming is assumed to be most valuable during the hours of 12:00 p.m. to 5:00 p.m., weekdays during the summer peak demand season (May through October). Because there is also some benefit associated with energy time-shift during the winter demand season (November through April), it is also assumed that the storage is used for energy time-shift during those months, for the same five hours per day on weekdays.

5.2.16.5. Energy for Renewables Capacity Firming

Readers should note that the renewables capacity firming benefit estimated does not include benefits related to the *energy* that is discharged when storage is being discharged to firm renewable energy generation output. If storage (used for renewables capacity firming) is discharged for a small portion of the year, then the energy-related benefit may be modest. Conversely, the energy-related benefit could be more significant if storage is discharged for a larger portion of the year.

Although each circumstance is different, the total benefit for renewables capacity firming is often maximized by using low-priced, off-peak wholesale energy from the grid to charge storage. Furthermore, all energy output from the renewable energy generation is delivered directly to the grid without storage losses. Among other effects, storing low-priced energy from the grid *and* directly from renewable energy generation means that there is more energy output from the renewable energy plus storage system than could be delivered if only energy from renewable energy generation is stored.

For this report, the *wholesale* energy prices used to estimate energy benefits associated with renewables capacity firming are the same ones used for the electric energy time-shift benefit (See Section 5.2.1). Monthly and seasonal average price *differentials* for the prices used are summarized in Table 26 in the description of the renewables energy time-shift benefit (See Section 5.2.15). The price differential is the difference between on-peak energy and off-peak energy during weekdays.

5.2.16.6. Distributed PV Capacity Firming

In many parts of California, well-designed and well-operated solar generation provides a capacity credit of 0.80 or more, in part because of the good correlation between insolation and demand.[74]

For the purpose of this guide, however, the solar generation that is firmed (*i.e.*, distributed, flat-panel PV modules with a fixed orientation) is assumed to have a capacity credit of 0.40. That value is lower than the 0.80 capacity credit for a well-optimized, solar generation facility for several reasons.

First, PV systems evaluated herein have a fixed orientation; however, generation with a high capacity credit uses ‘tracking’ to follow the sun, so the solar collector is pointed directly at the sun for a large portion of the day. The result is more power production during peak demand periods and more energy generation during the year than a similar plant that does not employ tracking, though tracking adds complexity and cost.

Other reasons that distributed PV systems’ capacity credit may be relatively low include the following: the PV modules’ (fixed) orientation is suboptimal; regular dust accumulation on modules; shading of PV modules by trees, buildings, *etc.* during a portion of the peak demand period; high ambient temperatures that reduce PV's efficiency and power during the peak demand period; and the level of cloudiness over the PV's location.

Storage is used to firm PV during the five peak demand price hours in the summer months. For this report, the generic peak demand period assumed is 12:00 p.m. to 5:00 p.m., weekdays, during the summer peak demand season (May through October).

The generic storage discharge duration for storage plus PV systems ranges from 2 to 3 hours, though the discharge duration could be less in regions with good insolation and/or for well designed and maintained PV systems.

The storage plus PV system is assumed to operate as follows for PV capacity firming: low-value (and low-priced) energy *from the grid* is stored, and that energy is discharged during utility peak demand hours. Because most or all energy generated by PV has high or relatively high real-time value, all PV energy is assumed to be used or sold to the grid as it is generated.

For this analysis, adding storage to distributed fixed-orientation PV is assumed to increase the capacity credit from 0.40 to 1.0. Although a given storage plus PV system may not be reliable enough to warrant a capacity credit of 1.0, it is assumed that that unit diversity among many small storage plus PV systems leads to an effective aggregated electric supply capacity credit *approaching* 1.0.

5.2.16.7. Bulk Wind Generation Firming

Capacity firming could be applied to smaller distributed wind generation capacity; however, in this guide the wind generation that is firmed is assumed to be deployed in central/large-scale wind farms. The generic capacity credit assumed for wind generation is 0.25.[75]

Note that most *energy* production from wind generation is assumed to occur when the energy has relatively low value (*i.e.,* most energy produced is generated during evening, night, and early morning hours).

Depending on the duration of the peak demand period and the degree to which wind coincides with peak load, storage used to firm wind generation capacity is assumed to have a discharge duration of 3 to 4 hours (3.5 hours is the generic value used.)

After being firmed with storage, the wind generation is assumed to have a capacity credit approaching 1.0 (0.75 of which is attributable to the addition of storage).

5.2.16.8. Distributed Renewables Capacity Firming for Demand Charge Reduction

Note that the renewables capacity firming benefit is related to electric *supply* capacity. That is, the benefit described above is related to the avoided cost of owning a generation plant. In the previous example, the generation is a generic dispatchable resource.

An important analog for electricity *end users* allows them to derive a benefit for capacity firming based on the applicable tariff for electric service. If the end user's electric service tariff includes demand charges, then the end user could use storage to reduce those charges. Demand charges reflect the price charged by the utility for each kW of *power* draw (demand) by the end user. (See Section 3.5.2 and Section 5.2.12 for more details about demand charge reduction using storage.)

5.2.16.9. *Incremental Benefit and Cost for Adding Storage for Renewables Capacity Firming*

One point worth noting is that the renewables capacity firming benefit estimated in this report is for *adding* storage to renewable energy generation, so the benefit is *incremental*. Consequently, when evaluating the financial merits of adding storage to renewables generation, the incremental benefit is compared to incremental cost (to add storage).

5.2.16.10. *Estimate*

The renewables capacity firming benefit is based on the avoided cost for generation capacity of \$120/kW-year and on the degree to which the renewable energy generation output is firmed. As an example: For PV, the assumed capacity credit *before* firming is 0.4, whereas the assumed capacity credit *after* firming is 1.0, for an increase of

$$1.0 - 0.4 = 0.6 \text{ kW per kW of rated capacity.}$$

The resulting capacity firming benefit is

$$0.6 \times \$120/\text{kW-year} = \$72/\text{kW-year}.$$

The energy-related benefit (for the energy discharged from storage) is summarized in Table 27. The total annual benefit, including the capacity-related benefit plus the energy-related benefit, is summarized in Table 28.

Table 27. Energy Time-shift Benefit from Renewable Energy Generation During Operation for Capacity Firming

	Photovoltaics		*Wind Generation*	
	Summer	Winter	Summer	Winter
Net Unit Benefit (\$/MWh)[1]	60.3	22.2	60.3	22.2
(¢/kWh)	6.03	2.22	6.03	2.22
Energy Time-shift (Hours/Day)[2]	2.5	2.5	3.5	3.5
Days/Year[3]	130	130	130	130
Hours/Year	326	326	456	456
Net Seasonal Benefit (\$/kW-yr)	19.7	7.2	27.5	10.1
Net Annual Benefit (\$/kW-yr)	**26.9**		**37.6**	

1. On-peak energy price minus off-peak energy price minus cost for storage losses. Does *not* include consideration of storage VOC.
2. This criterion is based on the storage discharge duration.
3. This criterion is based on the definition of peak demand period.

Table 28. Total Annual Renewables Capacity Firming Benefit

	Storage Energy	*Renewables Effective Capacity* [1]		*Storage Incremental* Value ($/kW-yr)		
	Discharge Duration	w/o Firimg	Firmed	Capacity[2]	Energy	Total
PV	2.5	0.40	1.00	72.0	26.9	98.9
Wind	3.5	0.25	1.00	90.0	37.6	127.6

1. During peak demand periods.
2. Assuming $120 per kW-year for combustion turbine based generation.

The annual values are converted to 10-year lifecycle benefit by multiplying by the PW factor of 7.17. The estimated 10-year net benefit associated with firming of PV output is

$98.9/kW-year × 7.17 = $709/kW.

The estimated 10-year net benefit from firming of wind generation is

$127.6/kW-year × 7.17 = $915/kW.

5.2.17. Benefit #17 — Wind Generation Grid Integration

5.2.17.1. Description

The wind generation grid integration (wind integration) application includes two categories and a total of six subtypes. The two categories are 1) short-duration (lasting for a few seconds to a few minutes) and 2) long-duration (lasting for many minutes to a few hours). The six subtypes are summarized in Table 29.

Table 29. Wind Generation Grid Integration Application Subtypes

Short-duration Applications
1. Reduce Output Volatility (due to momentary wind fluctuations)
2. Improve Power Quality
Long-duration Applications
3. Reduce Output Variability (lasting minutes to hours)
4. Transmission Congestion Relief
5. Backup for Unexpected Wind Generation Shortfall
6. Reduce Minimum Load Violations

The benefit associated with storage used for each subtype varies significantly. Even among the subtypes, the benefit varies from moment-to-moment, throughout the day, throughout the year and from year-to-year.

Benefit values for wind generation grid integration in this guide provide a starting point for related analyses, rather than being definitive. The rationale used to establish each benefit value is described below. Readers are left to judge the merits of that rationale for a specific region, electric supply system, or wind generation resource.

5.2.17.2. Estimate

The methodology for estimating each of the six wind generation grid integration application subtypes varies. A brief discussion of each is provided below.

Reduce Output Volatility

The leading response to grid effects from wind output volatility (characterized by variations lasting a few seconds to a few minutes) is increased use of conventional area regulation resources. For this report, the benefit for reducing aggregate wind output volatility is the avoided cost for that additional area regulation service needed to accommodate the volatility. The area regulation service is described in Section 3.3.2 and the benefit is described in Section 5.2.4.

(An alternate approach that could be used to estimate the benefit for short-duration intermittency is that used for the renewables capacity firming application in Section 5.2.16.)

Area regulation capacity needed to accommodate wind generation additions is assumed to be required during the six most productive months for wind generation (which varies depending on region). Consequently, the benefit estimate is about half that for *annual* operation. If storage can provide *rapid-response* regulation, and if the benefit from that capability can be internalized by the storage owner, then the benefit can be as high as $1,000/kW for 10 years. If the rapid-response capability does not have a specified value, then the 10-year benefit may be closer to $500/kW. In this guide, the estimated generic benefit is $750/kW for 10 years.

Improve Power Quality

The benefit for improved power quality is specific to the location, wind resource, and wind turbine type(s), and it varies from moment-to-moment, throughout a day, throughout the year, and among years. Also, newer wind turbines pose fewer and less significant power quality-related challenges than older turbines.[76]

The first option for establishing the benefit for this application is to determine the cost of the most likely existing option for addressing the specific power quality challenge and, in some cases, the 'do nothing' option. Conventional options may include replacing components of older wind turbines; upgrading circuits and/or transformers; using capacitors, static VAR compensators, or power electronics; curtailing production from wind generation; and/or using on-site/local dispatchable (*e.g.*, diesel-fueled) generation. Given the challenge of generalizing the circumstances and options for this application, estimating a generic benefit is probably not helpful, so no estimate is provided in this report.

Reduce Output Variability

Wind generation output variability involves changes that occur over periods lasting from minutes to hours. Wind variability (from minute-to-minute and throughout the day) adds to the need for load following resources that must make up the difference between load and generation that is already online. For this guide, the benefit of reducing aggregate wind output variability is the avoided cost for that additional load following service.

It is also assumed that most additional load following capacity will probably be provided by combined cycle generation plants. Furthermore, the additional load following is assumed to be needed for six hours per day (three hours during the morning when load is increasing, and three hours as load decreases at night) which is assumed to occur during the six most productive wind generation months each year.

Given that the service is provided by a combined cycle power plant, the assumed (marginal) cost for the additional service is \$50/MW per service hour. As a result, the estimated annual benefit (in Year 1) for using storage with wind generation to reduce the need for additional load following resources is

6 hours/day × 7 days/week × 26 weeks/year) × \$50/MW per hour of service

= 1,092 hours/year × \$50/MW per hour of service

= \$54,600/MW per year of service (\$54.6/kW-year).

The generic lifecycle benefit is

\$54.6/kW-year × 7.17 = \$391.5/kW.

Transmission Congestion Relief

The transmission congestion relief application subtype cannot be easily generalized. In some areas, there may be enough unused transmission capacity to accommodate all, or at least most, expected wind generation capacity additions. In other areas, any significant additions may overwhelm existing transmission capacity. In some cases, congestion is reflected in pricing for energy or for energy transfers.

The cost to upgrade transmission to accommodate renewables in California probably reflects relatively high costs (for new transmission capacity); however, it may still be instructive to consider the circumstances. In California, cumulative wind generation capacity additions are assumed to be 5,200 MW by 2010 and 10,600 MW by 2020. The total installed cost for new transmission capacity needed to accommodate *all* renewables in California is an estimated \$2.3 billion by 2010 and \$6.3 billion by 2020.[77] For this report, it is assumed that about two-thirds of the transmission cost for all renewables is attributable to *wind* generation additions (given that most new renewable generation capacity expected is wind generation).

Based on those assumptions, the estimated lifecycle cost for transmission capacity needed to accommodate wind generation capacity additions is shown in Table 30. The approach used to make that estimate is described below.

Table 30. Estimated Total Transmission Cost for Wind Capacity Additions in California

	Year	2010	2020
1	**Wind Capacity Additions (MW cum.)**	**5,200**	**10,600**
2	Transmission Total Installed Cost ($Million)	2,300	6,300
3	(Assumed) Portion of Transmission Attributable to Wind Gen. added	0.667	0.667
4	Transmission Cost Attributable to Wind Gen. added ($Million)	1,534	4,202
5	**Transmission *Annual* Cost for Wind Gen. Added ($Million)***	**168.8**	**462.2**
6	Transmission Cost for Wind Gen. / Wind Gen. kW ($/kW of Wind gen.)**	295	396
7	Transmission Annual Cost for Wind Gen. / Wind Gen. kW ($/kW-year of Wind gen.)	32.5	43.6
8	**Transmission Lifecycle Cost for Wind Gen. ($/kW of Wind gen. for 10 years)***	**232.7**	**312.7**
9	(Assumed) kW storage per kW of Wind gen.	0.50	0.50
10	**Lifecycle Benefit ($/kW storage, 10 years)**	**465.4**	**625.3**

* Attributable to wind generation. Based on Fixed Charge Rate = 0.11

** Transmission Annual Cost / Wind Capacity Additions

*** 10.0%/yr. discount rate, 2.5%/yr. escalation rate: PW factor = 7.17

The approach used to estimate the transmission congestion relief benefit involves assumptions about or estimates of 1) wind generation capacity to be added; 2) transmission capacity needs and the related total and annual cost attributable to increased wind generation capacity to be added (key premise: wind generation-related transmission congestion will occur if that transmission capacity is not added); 3) the value of a 10-year deferral of the upgrades needed; and 4) the lifecycle (10 year) benefit if storage is used *in lieu* of upgrades.

The following ten-step process was used to develop the generic benefit estimate shown in Table 30:

1. Determine the total amount of wind generation to be added (Line 1 in Table 30).
2. Use a current estimate of transmission *total cost* that will be incurred because all types of renewables generation will be added (Line 2 in Table 30). Total cost is defined as the *installed* cost, including land, site preparation, permits, equipment purchases, and installation.
3. Estimate the *portion* of transmission total cost that is attributable to wind generation additions (line 3 in Table 30). For the example, wind generation is assumed to account for two-thirds of the transmission needed to accommodate all renewables.
4. Calculate the *value* of transmission total cost that is attributable to wind generation additions. In the example, multiply the transmission total installed cost for renewables (Line 4 in Table 30) by two-thirds. For the example, an estimated $1.53 billion would be spent in 2010 and $4.2 billion would be spent in 2020.
5. Calculate the *annual* (financial carrying) cost for the transmission attributable to wind generation additions by multiplying the transmission total cost that is attributable to wind generation additions (Line 4 in Table 30) by the fixed charge rate of 0.11. The result (Line 5 in Table 30) is approximately $169 million in 2010 and $462 million in 2020.

6. Allocate transmission *total* cost attributable to wind generation additions to wind generation on a $/kW of wind generation basis. That is done by dividing the transmission cost attributable to wind generation added (Line 4 in Table 30) by the kW of wind generation to be added (Line 1 in Table 30). The result is $295/kW of transmission installed cost per kW of wind generation capacity added by 2010 and $396/kW of wind generation added by 2020 (Line 6 in Table 30).
7. Allocate the *annual* cost for transmission needed to serve new wind generation, on a $/kW of wind generation basis. That is done by dividing the *annual* transmission cost attributable to wind generation additions (Line 5 in Table 30) by the kW of wind generation to be added (Line 1 in Table 30). In 2010, the resulting single-year transmission cost is about $186 Million ÷ 5,200 MW = $32.5 per kW-year of wind capacity. In 2020, the annual cost for transmission added (per kW of wind generation added) is $462 Million ÷ 10,600 MW = $43.6 per kW-year (Line 7 in Table 30).
8. Estimate the *lifecycle* transmission cost attributable to wind generation additions by multiplying the annual transmission-related cost per kW of wind generation (Line 7 in Table 30) by the present worth factor of 7.17. That yields an estimated lifecycle cost for wind generation capacity added of $232.7/kW by 2010 and $312.7/kW by 2020 (Line 8 in Table 30).
9. Estimate the amount of storage needed (per kW of wind generation) to avoid the need for additional wind generation-related transmission. In the example, the assumption is that 0.5 kW of storage (whose useful life is 10 years) is needed per kW of wind generation to offset transmission-related cost (Line 9 in Table 30). That is based on the simplifying assumption that in almost all cases wind generation output will not be more than 50% of its rated capacity during times when the transmission system is heavily loaded, overloaded, or congested.
10. Calculate the 10-year lifecycle benefit associated with each kW of storage used to provide transmission congestion relief (based on deferring transmission upgrades for 10 years). That value is derived by dividing lifecycle transmission cost attributable to wind generation additions (Line 8 in Table 30) by 0.5 (kW storage / kW wind generation). For the generic estimate, the benefit is $465.4/kW in 2010 and $625.3/kW in 2020 (Line 10 in Table 30).

This benefit estimate reflects the *average* cost for transmission. Presumably, there are some locations for which the cost to upgrade the transmission is higher. Furthermore, it is those locations for which storage may be the best alternative (given the relatively high cost).

Consider another scenario: For the situation described above, 50% of all wind-related transmission upgrade costs are incurred to accommodate 20% of the wind capacity additions. Furthermore, those locations require 1 kW of storage per kW of wind generation to avoid the need to upgrade transmission equipment. The results of this scenario are shown in Table 31.

Table 31. Transmission Cost for Wind Capacity Additions in California, High-value Locations

	Year	2010	2020
1	Wind Capacity Additions (MW cum.)	5,200	10,600
2	Applicable Portion*	0.2	0.2
3	**Wind Capacity Affected (MW cum.)**	**1,040**	**2,120**
4	Transmission Total (Installed) Cost ($Million)	2,300	6,300
5	(Assumed) Portion of Transmission Total Cost Attributable to Wind Gen. Added	0.667	0.667
6	Transmission Total Cost Attributable to Wind Gen. Added ($Million)	1,534	4,202
7	Portion (of cost for all transmission additions) In Play*	0.5	0.5
8	Transmission Cost Attributable to Wind gen. added ($Million)	767	2,101
9	**Transmission Annual Cost for Wind Gen. Added ($Million)****	**84.4**	**231.1**
10	Transmission Total Cost for Wind Gen. / Wind Gen. Added kW ($/kW of Wind Gen.)**	738	991
11	ısmission Annual Cost for Wind Gen. / Wind Gen. Added kW ($/kW-year of Wind Gen.)	81.1	109.0
12	**Transmission Lifecycle Cost for Wind Gen. Added ($/kW of Wind gen. for 10 years)*****	**582**	**782**
13	(Assumed) kW storage per kW of Wind Gen. Added	1.00	1.00
14	**Lifecycle Benefit ($/kW storage, 10 years)**	**582**	**782**

* 50% of all costs attributible to Wind gen. are incurred for 20% of Wind gen. additions.

** Attributable to wind generation. Based on Fixed Charge Rate = 0.11

*** 10% discount rate, 2.5% escalation rate: PW factor = 7.17

Based on the results shown in Table 31, the lifecycle benefit for storage used to offset need for the most expensive transmission upgrades (those needed to accommodate wind generation) would be $582/kW over 10 years in 2010 and $782/kW over 10 years in 2020 (Line 1 in Table 31).

Based on the results for the two scenarios shown in Table 30 and Table 31, the *generic* value assumed for the lifecycle benefit is $625/kW for 10 years.

Backup for Unexpected Wind Generation Shortfall

The value for this application is related to avoiding electric service outages that are caused by a sudden, unexpected drop in wind generation output. To the extent that storage allows grid operators to avoid such outages, the storage provides benefit. It is important to note that, in most cases, the ISO addresses a sudden reduction of wind generation output with one of several non-storage options, especially out-of-area energy purchases; reserve capacity; interrupting or curtailing load to reduce demand; and increasingly automated load control. Storage provides another option.

The values in Table 32 reflect a simple benefit estimate based on the value-of-service (VOS) metric described in Section 5.2.13. The assumed composite VOS for all customer classes is $10/kWh. That value reflects the cost incurred by end users per kWh of energy not delivered due to the outage. Furthermore, it reflects a composite of the value for all electricity end-user classes, ranging from residential end users at the low end, for whom the cost is close to nothing, to high-value-added manufacturing customers whose VOS may exceed $100/kWh. As shown in the table, at the lower bound, one outage is avoided over 10 years for an estimated 10-year lifecycle benefit of $100/kW or an annual benefit of about $14/kW-year. At the high end, two outages are avoided over 10 years, yielding an estimated lifecycle benefit of $200/kW and an annual benefit of $28/kW-year.

Table 32. Benefit for Avoided Service Outages Due to Sudden Drop of Wind Generation Output

	Low	High
Wind-to-Peak Load Ratio	10.0%	10.0%
Outages Avoided (10 years)	1	2
Outage Duration (hours)	1	1
Value of Unserved Energy ($/kWh)	10	10
Lifecycle Benefit ($Year1 / kW-*load*)	10	20
Lifecycle Benefit* ($ Year 1 / kW *wind gen.*)	100	200
Annual Benefit** ($/kW-year)	14	28

*Lifecycle Benefit per kW of Load / Wind/Peak Load Ratio.
**Assuming PW factor = 7.17

For the estimate above, it is assumed that there is 1 kW of storage per kW of wind generation. To the extent that wind resources are geographically diverse, less than 1 kW of storage per kW of wind generation is conceivable. If, for example, storage of 0.5 kW per kW of wind generation capacity would suffice for a geographically diversified wind generation resource, then the benefit values in Table 32 would double.

Reduce Minimum Load Violations

Minimum load violations occur when generation capacity exceeds demand. When that occurs, some of the energy generated may not be usable. The benefit for reducing minimum load violations is assumed to be related to the value of energy that cannot be used. The generic value is estimated based on forecasted energy prices in California in 2009. A summary of those values is shown in Table 33.

Table 33. Low and High Values for Minimum Load Violations

Item Name	Low	High
Portion of the Year	1.0%	4.0%
Hours Per Year	87.6	350.4
Energy Price ($/MWh)	56.5	56.5
Benefit ($/MW-year)	4,949	19,798
($/kW-year)	4.9	19.8

Based on the values shown in Table 33, the generic value for reduced minimum load violations ranges from about $5/kW-year on the low end to about $20/kW-year on the high end. The low value reflects minimum load violations that occur during 1% of the year, or about 57 hours per year. The high value reflects minimum load violations occurring during 4% of the year, or 350 hours per year. Both values reflect an average energy price of $56.5/MWh during minimum load violations.

5.2.17.3. Wind Integration Benefits Summary

Table 34 summarizes the benefits estimated (and described above) for the wind integration application subtypes.

Table 34. Wind Integration Benefits Summary

	Benefit Estimate ($/kW)*	
Application Subtype	Low	High
Short Duration		
1. Reduce Output Volatility (due to momentary wind fluctuations)	500	1,000
2. Improve Power Quality	not estimated	
Long Duration		
3. Reduce Output Variability (lasting minutes to hours)	391	
4. Transmission Congestion Relief	465	782
5. Backup for Unexpected Wind Generation Shortfall	100	200
6. Reduce Minimum Load Violations	5	20

* 10 years, 2.5% escalation rate, 10% discount rate: Present Worth factor = 7.17.

5.3. Incidental Benefits

Some benefits are not specific to any one application, as they may accrue incidentally when storage is used for one or more applications. For example, dynamic operating benefits occur because the operation of the greater electric supply system is more optimal because storage is used. And, although avoiding transmission access charges is not an application, it may be that using storage allows stakeholders to reduce or avoid charges associated with transmitting energy through the transmission system. A discussion of nine meaningful incidental benefits which are explored in this guide is provided below.

5.3.1. Benefit #18 — Increased Asset Utilization

5.3.1.1. Description

In many situations, use of energy storage will increase the amount of electricity that is generated, and/or transmitted, and/or distributed using existing utility assets. The effect is commonly referred to as increased asset utilization. Two important financial implications of increased asset utilization are 1) the cost to own the equipment is amortized across more (units of) energy which reduces the unit cost/price for that energy, and 2) the payback from the investment occurs sooner, which reduces investment risk.

Consider an example: A utility installs distributed energy storage to address local electric service reliability needs and to defer an expensive T&D upgrade. Storage use increases generation asset utilization if the storage is charged using *existing* generation assets (presumably during times when demand is low). Similarly, transmission asset utilization increases assuming that *existing* transmission capacity is used to transmit the storage charging energy (presumably the transmission occurs during times when transmission asset utilization is normally low). Depending on use patterns and location, distributed energy storage may also increase distribution asset utilization.

The benefit of increased asset utilization is highly circumstance-specific. It is not estimated in this guide.

5.3.2. Benefit #19 — Avoided Transmission and Distribution Energy Losses

5.3.2.1. Description

As with any process involving conversion or transfer of energy, energy losses occur during electric energy transmission and distribution. These T&D energy losses (sometimes referred to as I^2R or 'I squared R' energy losses) tend to be lower at night and when loading is light and higher during the day and when loading is heavy. T&D energy losses increase as the amount of current flow in T&D equipment increases and as the ambient temperature increases. Thus, losses are greatest on days when T&D equipment is heavily loaded and the temperature is high.

If storage is charged with grid energy, then the benefit is based on the difference between the cost for losses incurred to deliver energy for charging (off-peak) and the cost that would have been incurred if the energy was delivered in real-time (on-peak). If storage is charged with energy generated locally, then the losses avoided (and benefit) may be even higher because no/limited losses are incurred to get the energy to the storage for charging.

5.3.2.2. Estimate

The generic benefit values shown in Figure 19 reflect two energy price scenarios and two scenarios for on-peak *versus* off-peak losses. The first price scenario involves an average price *difference* (labeled as Price Δ in the figure) of 6 ¢/kWh between on-peak and off-peak energy prices. For the second scenario, the average *difference* between on-peak and off-peak energy prices is 8 ¢/kWh. The values in Figure 19 also reflect a T&D energy loss *difference* (labeled as Loss Δ in the figure) between on-peak and off-peak of 3% at the low end and 5% at the higher end. An example: If on-peak T&D losses are 8% and T&D losses off-peak are 5%, then the *difference* is 3%. The estimated generic benefit for avoided T&D I^2R energy losses is $8/kW-year (net) or about $57/kW over 10 years.

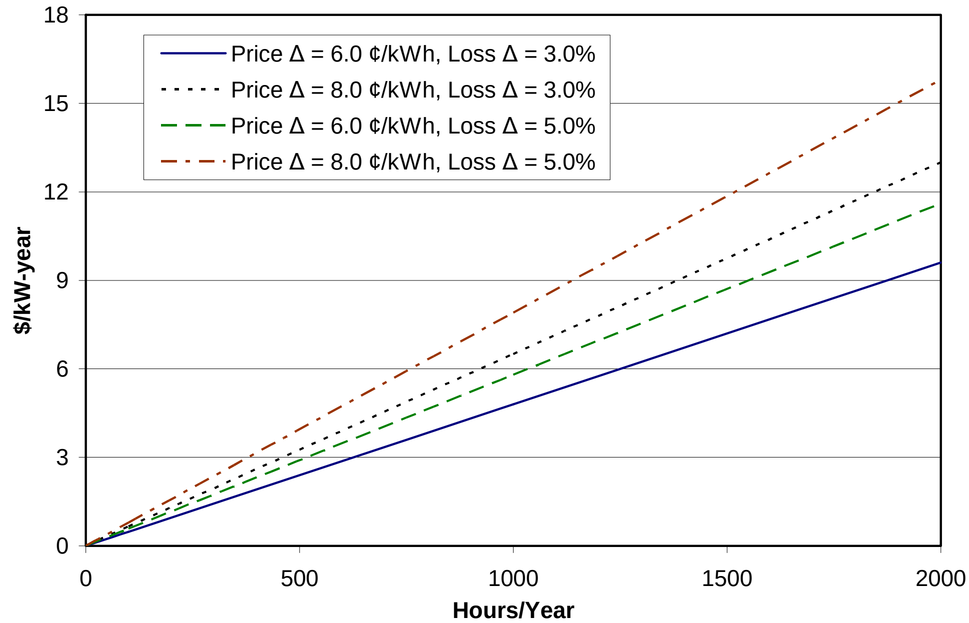


Figure 19. Benefit for T&D I^2R energy losses avoided.

5.3.3. Benefit #20 — Avoided Transmission Access Charges

5.3.3.1. Description

Typically, utilities that transmit electricity across transmission facilities that are owned by another entity must pay the owners for transmission 'service'. Similarly, utility customers must pay the cost incurred by the utility to own and to operate transmission needed to deliver the electricity. Related charges are often called transmission access charges.

Consider municipal electric utilities (munis) and electric cooperatives (co-ops). Munis and co-ops may own some or all of the generation capacity needed. Almost all munis and co-ops own and operate their electricity distribution system. Many, however, do not own transmission capacity. Also, most utilities transmit some power through other utilities' transmission lines. Utilities must pay transmission access charges to transmit power from their own generation plant(s) and/or from the wholesale electricity marketplace.

The benefit for avoided transmission access charges depends on, among other factors, tariff terms and pricing, location, and increasingly, time of year and time of day. In some cases, transmission access is priced based on energy used ($/kWh delivered). In other cases, the transmission charge is assessed based on capacity used, like demand charges ($/kW).

In many parts of the country, the marketplace for transmission capacity is just emerging. As the marketplace for electricity opens up, transmission access charges will be available from the various regional transmission organizations. The trend toward locational marginal pricing of energy will allow for increasingly precise, location-specific allocation of transmission costs.

5.3.3.2. Estimate

At the lower end of the spectrum, transmission access charges are estimated based on annual average transmission charges for firm point-to-point transmission service in the Midwest ISO control area. Based on an informal survey of those transmission access charges, the annual amount is approximately \$25/kW-year to \$30/kW-year.[78] Furthermore, the Midwest ISO's charges for off-peak transmission service are on the order of 30% less than the charge for service on-peak.

At the high end of the spectrum, consider a California-specific indication of the *retail* charge for transmission: A transmission access charge of 0.913 ¢/kWh of energy delivered is assessed for transmission under terms of PG&E's A-6 commercial TOU energy price electricity service tariff. If assuming annual energy use of 4,300 kWh per kW of peak load, the total transmission charges are about \$40/kW-year.[79]

Note that the value of \$40/kW-year is assumed to indicate the utility 'revenue requirement' for transmission which is the amount that the utility must collect as revenue from customers to cover cost. Furthermore, if transmission is priced based on energy delivered, rather than being based on peak demand, then storage could actually increase transmission charges for end users because for each kWh discharged from storage, transmission charges are incurred for storage charging energy *and* for storage energy losses. Finally note that, in some cases, transmission charges are lower at night than during the day.

The estimated generic benefit for avoided transmission access charges is \$20/kW-year. After applying the 7.17 PW factor, the lifecycle benefit is \$143.40/kW.

5.3.4. Benefit #21 — Reduced Transmission and Distribution Investment Risk

5.3.4.1. Description

Although there is no specific accounting for or price ascribed to it, there is an undetermined amount of risk associated with investments in T&D upgrades or expansion, as there is with *any* investment. While there is no formal way to account for that risk, it is an actual cost borne by electricity users.*

Consider a simple example: Utility power engineers decide that it is prudent to upgrade some T&D equipment. When the upgrade project is half finished, the utility receives news that a large customer load will be removed such that the in-process upgrade will not be needed for several years. Whether the project is completed or not, for several years no revenue is received to cover the cost incurred for the upgrade. As a result, utility customers at large must pay more to cover that unmet revenue requirement. The effect is the same if *aggregate* load growth is lower than expected.

Uncertainty can lead to T&D project delays, the result of which may be service outages and damage to existing equipment. Some sources of uncertainty that can cause costly project delays include a) utility staff or funding shortages, b) institutional delays such as those for permits, c) unforeseen challenges encountered during construction, and d) weather.

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* Although not addressed in this report, storage could also be used to reduce generation fuel price risk.

For most T&D upgrades, the investment risk is low to very low. A low-risk T&D investment tends to involve an upgrade that is routine, low cost, and whose cost is likely or very likely to be offset by revenues.

Storage – or any other *modular* resource that can be located downstream (electrically) from the T&D upgrade – can be used to manage risk. For example, if there is uncertainty about whether an expected block load addition will occur or staffing shortages or permitting delays will affect the upgrade, modular storage could be used to defer the upgrade for one year – enabling the utility to delay a possibly risky T&D upgrade investment until there is less uncertainty.

It is not possible to generalize this benefit given the wide range of possible circumstances that could be involved; therefore, an estimate is not provided in this guide.

5.3.5. Benefit #22 — Dynamic Operating Benefits

A dynamic operating benefit (DOB) is a *generation* operating cost that is reduced or avoided because storage is part of the electric supply system. Generation operating cost is reduced if generation equipment a) is used less frequently (*i.e.*, has fewer startups), b) operates at a more constant output when it is used (avoided part load operation), and c) operates at its rated output level most/all of the time when in use.[80]

DOBs include those for reduced generation equipment wear, reduced fuel use, and reduced emissions. Reducing equipment wear may reduce maintenance costs and/or extend equipment service life. Fuel use and emissions are reduced if a) generation output is more constant, b) generation output operates at its rated output, and c) generation is started less frequently.

Some of the DOBs reflect expenses that would otherwise be incurred by utilities and that would be reflected in utility service prices. Other DOBs reduce societal costs. DOBs that reduce actual expenses include reduced fuel cost, reduced maintenance cost, and increased equipment life. The key societal benefits include lower cost-of-service, reduced resource (fuel) use, and reduced air emissions.

This benefit is specific to the generation mix in a given region. It is not estimated in this guide.

5.3.6. Benefit #23 — Power Factor Correction

As described in Appendix C, utilities often need to compensate for reactance that causes unacceptably low power factor. The typical utility response – to improve a circuit's power factor and effectiveness – is twofold: 1) include a (low) power factor charge for commercial electricity end users' whose loads have an especially low power factor (*e.g.*, below 0.85) and 2) use capacitors to offset the effects from inductive loads (*i.e.*, to reduce the degree to which voltage and current are out of phase).

Depending on circumstances, the utility solution may involve other more expensive alternatives such as static synchronous compensators (StatComs) and static VAR compensators.

Depending on the type and characteristics of storage deployed, distributed storage could provide effective power factor correction. Battery or other storage systems whose storage media has direct current (DC) output and which include power conditioning to convert between AC and DC power are especially well-suited to power factor correction. Conventional motor-generator systems can also provide reactive power (VAR) needed for local power factor correction.

Notably, power factor correcting capacitors (the most common approach used by utilities for power factor correction) are inexpensive relative to generation capacity. Typical installed costs range from $10 to $15 per kVAR, so the avoided cost (benefit) if storage is used would be low (relative to storage system cost). Nonetheless, that benefit may still be attractive if the *incremental* cost to add power factor correction capability to storage is low enough.

5.3.7. Benefit #24 — Reduced Generation Fossil Fuel Use

One incidental benefit that may accrue if storage is used is a reduction in the use of fossil fuels used for generation. Storage use can lead to reduced fossil fuel use in at least three ways. First stored energy from more efficient fossil fueled generation and/or renewables can offset use of less efficient intermediate duty or peaking generation (energy time-shift). Second, fuel use may be reduced due to dynamic operating benefits associated with storage use (Benefit #22). Third, fossil-fueled generation tends to be more efficient when ambient temperatures are low. Coincidentally, most storage charging occurs at night, when temperatures are lower. Finally, if energy is transmitted at night when ambient temperatures and T&D loading are relatively low, then T&D energy losses are reduced (Benefit #21).

Importantly, the degree to which fuel use is reduced *or increased* (due to use of storage) depends on three key criteria: 1) the age and type of generation equipment and fuel used to generate electricity for charging storage, 2) the age and type of generation equipment and fuel that *would have been used* if storage is not deployed, and 3) storage efficiency (*i.e.*, losses).

Consider a simple example: Combined cycle combustion turbine generation (CC) whose fuel efficiency is 49% (requiring 6,965 Btu/kWh of fuel, often referred to as the generator's 'heat rate') and simple cycle combustion turbine generation (CT) whose fuel efficiency is 33% (for a heat rate of 10,342 Btu/kWh of fuel). The fuel use difference between those two generators is

10,342 Btu/kWh on-peak – 6,965 Btu/kWh off-peak = 3,377 Btu/kWh

3,377 Btu/kWh difference ÷ 10,342 Btu/kWh on-peak = 32.7%.

Then, if storage efficiency is 75%, then the *net* amount of fuel used to generate charging energy for storage is

6,965 Btu/kWh off-peak ÷ 75% efficiency = 9,292 Btu/kWh.

The result is a fuel use reduction of

10,342 Btu/kWh on-peak – 9,292 Btu/kWh charging = 1,055 Btu/kWh

1,055 Btu/kWh difference ÷ 10,342 Btu/kWh on-peak = 10.2%.

The above example and another involving charging with electric energy from coal generation are summarized in Table 35.

Table 35. Generation Fuel Use Implications of Energy Storage Use

Scenario	Off-peak/Charging: Fuel[1] Efficiency (%)	Off-peak/Charging: Heat Rate[1] (Btu/kWh)	On-peak/Avoided: Fuel[1] Efficiency (%)	On-peak/Avoided: Heat Rate[1] (Btu/kWh)	Difference: Net Fuel Use[2, 3] (Btu/kWh)	Difference: Change of Fuel Use[4] (Btu/kWh)
Charge: Combined Cycle Avoid: Simple Cycle C.T.	49.0%	6,965	33.0%	10,342	9,287	-1,055 (-10.2%)
Charge: Advanced Coal Avoid: Simple Cycle C.T.	43.0%	7,937	33.0%	10,342	10,583	+241 (+2.3%)

1. In this context "fuel" only includes fossil fuels.
2. Off-peak generation fuel used, including additional fuel needed to make up for storage losses.
3. Storage efficiency = 75.0%.
4. Fuel use by on-peak resource (avoided) minus net fuel use for electrc energy used for charging.
C.T. = Combustion Turbine.

Notably, although the total amount of fossil fuel used for generation may be reduced if storage is used, the financial benefit associated with that reduction depends on the type and price of fuel(s) involved. Generally, the price for coal is lower than that for natural gas and petroleum-based fuels.

Given that this benefit is so circumstance-specific – being affected by on-peak and off-peak generation age and type, as well as on-peak and off-peak fuel type and price – it is not helpful to provide a generic value for fossil-fuel use reduction using storage, so no estimate is given.

5.3.8. Benefit #25 — Reduced Air Emissions from Generation

Reduction of air emissions from electricity generation is a potentially important incidental benefit of storage use. As with reduced fuel use (described above), there are at least four distinct ways that storage can reduce generation-related air emissions. The first involves using stored electric energy generated using relatively efficient and/or clean power plants (baseload and/or renewables) to offset the use of less efficient and/or dirtier on-peak generation (energy time-shift).

The remaining three ways that storage use can lead to reduced air emissions involve reduced *fuel use* (which presumably leads to reduced air emissions): 1) dynamic operating benefits (Benefit #22); 2) increased generation operation at night, for storage charging, when fuel efficiency is higher; and 3) reduced T&D energy losses that accrue if more energy is transmitted at night when T&D equipment is not heavily loaded and when ambient temperatures are lower (Benefit #21).

Importantly, storage-use-related air emission reductions are circumstance-specific. Specifically, the degree to which air emissions are reduced *or increased* (due to use of storage) depends on three key criteria: 1) the age and type of generation equipment and fuel used to generate electricity for charging storage, 2) the age and type of generation equipment and fuel that *would have been used* if storage is not deployed, and 3) storage efficiency (*i.e.*, losses).

Depending on the circumstances, storage could lead to reduced electricity generation-related emissions of carbon monoxide (CO_2), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), soot/particulate, carbon monoxide (CO) and volatile organic compounds.

Consider generic emission levels shown in Table 36 for NO_x and for CO_2. Values in that table are meant to indicate two common scenarios: 1) charge storage using off-peak electricity from a natural-gas-fueled combined cycle combustion turbine to offset use of a natural-gas-fueled simple cycle combustion turbine on-peak and 2) charge storage using off-peak electricity from modern coal-fueled generation to offset use of a natural-gas-fueled simple cycle combustion turbine on-peak. (Not shown is use of renewable energy to charge storage, which would lead to a dramatic reduction or even total elimination of air emissions per kWh from storage.) Based on the values in the table, storage would lead to dramatically different results depending on the type of generation involved.

Table 36. Generation CO_2 and NO_x Emissions Implications of Energy Storage Use

	Off-peak/Charging		On-peak/Avoided		Difference[1]	
Scenario	**CO_2** (lbs/MWh)	**NOx** (lbs/MWh)	**CO_2** (lbs/MWh)	**NOx** (lbs/MWh)	**CO_2** (lbs/MWh)	**NOx** (lbs/MWh)
Charge: Combined Cycle Avoid: Simple Cycle C.T.	922	0.260	1,131	0.320	+98.3 (+8.7%)	+0.027 (+8.3%)
Charge: Advanced Coal Avoid: Simple Cycle C.T.	2,222	3.620	1,131	0.320	+1,832 (+162%)	+4.51 (+1,408%)

Source: Hadley, S.W. VanDyke, J.W. Emissions Benefits of Distributed Generation in the Texas Market. Oak Ridge National Laboratory Report ORNL/TM-2003/100. April 2003.

1. These values reflect additional fuel used for generation required to make up for energy losses for storage whose efficiency = 75.0%

C.T. = Combustion Turbine.

Of course, it is necessary to ascribe a 'price' to (reduction of) a given type of air emission before the *internalizable* financial benefit can be estimated. That topic is beyond the scope of this study, so the financial benefit for emission reductions is not estimated.

5.3.9. Benefit #26 — Flexibility

In broad terms, flexibility can be defined as the degree to which and the rate at which adjustment to changing circumstances is possible. More specifically, flexibility may provide the means to respond adeptly to uncertainty. Flexibility allows decision makers to *manage* risk and even to take advantage of business opportunities involving risk (*i.e.,* to use 'real options'[81]).

Although it is almost impossible to generalize, in some circumstances there may be a significant financial benefit associated with flexibility, especially in a changing business environment with significant uncertainty. The benefit accrues if the flexibility allows selection and use of more optimal solutions or response to business-related needs, challenges, and opportunities. For example, modular electric resources (including storage) can be used to provide electric supply and/or T&D capacity 'on the margin,' when and where needed. In some cases that alternative could comprise a more optimal (financially) response than is possible using conventional ‘lumpy’ capacity additions. Indeed, depending on the circumstances, a more financially optimal solution can involve higher revenue, more profit, and/or lower cost per kW of load served.

This benefit is highly circumstance-specific and it is not estimated.

5.3.10. Incidental Energy Benefit

In some energy storage applications, energy is discharged incidentally during operation. That energy almost certainly has *some* value (benefit). For example, it may offset the need for a utility and/or a utility customer to purchase energy.

5.4. Benefits Not Addressed in This Report

As characterized in Section 3.8, the approach used in this guide does not address many storage applications explicitly. Similarly, this report does not address some benefits explicitly, especially those that are not ‘utility-related’.

Consider an example provided in Section 3.8 for an application involving storage for trackside support of electrified rail transportation systems. Two possible benefits for that application are a) increased revenue related to increased ridership and b) reduced equipment wear. Clearly, those benefits are not addressed explicitly in this guide, although they may actually exist and they may be important elements of an attractive value proposition. Also not addressed are possible tax-related incentives, especially income tax credits, and to a lesser extent, income tax deductions.

5.4.1. Utility Incentives, Special Tariffs and Pricing Approaches Not Addressed

5.4.1.1. Utility Incentives Not Addressed in This Report

Although not common practice, utilities may eventually provide incentives to customers to install storage. Those incentives could be similar to those used to encourage customers to install rooftop photovoltaics, to increase energy efficiency (of loads), and to participate in demand response, smart metering, and Smart Grid programs. Those incentives are an important element of storage value propositions.

5.4.1.2. Special Electric Service Tariffs and Pricing

In addition to the reduced time-of-use energy cost and reduced demand charges described in this report, there are at least three other possible ways that utility customers can use storage to reduce their overall electricity-related cost: 1) interruptible/ curtailable tariffs, 2) critical peak pricing, and 3) load management programs.

Interruptible/curtailable tariffs provide a discount to participants who agree to allow the grid operator to ‘curtail’ or ‘interrupt’ electric service when there is a shortage of energy and/or capacity. Normally, the agreement specifies that maximum frequency and duration of curtailments/interruptions. Historically, curtailment and interruption are used during electric *supply* shortages, though in the future, they could also be used when there is *transmission* congestion and/or when *localized* T&D overloading occurs.

Critical peak pricing involves energy prices that are significantly higher than normal and that apply when there is a shortage of energy and/or capacity. Normally, critical peak prices are invoked during electric *supply* shortages. In the future, they could also be used when *transmission* congestion exists and/or when *localized* T&D overloading occurs.

Load management programs incorporate pricing and/or direct load control to 'manage' peak demand during electric supply energy and/or capacity shortfalls. The objective is to create 'dispatchable' demand reduction (*i.e.*, utility customer loads that can be remotely controlled by the ISO, when needed, to address energy or capacity shortfalls.) When needed, the power draw of the demand response 'resource' is reduced, thereby reducing the need for generation.

5.4.1.3. Electric Service Pricing Approaches Not Addressed

In addition to time-of-use energy prices that reflect predetermined price for energy used within a predetermined time period, there is a steady movement toward 'dynamic' pricing involving energy prices that reflect current conditions and that may change as frequently as several times per hour. Similarly, there is movement to location-specific electricity prices, commonly referred to as locational marginal pricing (LMP). No attempt was made to address those pricing approaches in this report.

6. Storage Value Propositions

6.1. Introduction

This section provides an overview of the concept of storage value propositions, including coverage of important elements and considerations.

A value proposition is characterized by 1) one or more (combined) applications plus 2) attractive financial returns (*i.e.*, benefits that exceed costs by the 'hurdle rate' of return). In some cases, storage used for just one application may provide attractive returns. In other circumstances, it may be necessary to combine benefits from two or more applications so that total benefits exceed total cost. Hence, this report emphasizes the important concept of combining applications for benefits aggregation.

Of course, applications must be compatible if they are to be combined. A combination of applications is technically compatible if the same storage system can be used for all of the applications. A combination of applications has operational compatibility if there are no operational conflicts among the applications. As a general indication, the synergies matrix shown in Table 37 provides an overview of the possible compatibility among the various applications characterized in this document.

Table 37. Applications Synergies Matrix

● Excellent ◉ Good ⊙ Fair ○ Poor ⊗ Incompatible

Application	Electric Energy Time-shift	Electric Supply Capacity	Load Following	Area Regulation	Electric Supply Reserve Capacity	Voltage Support[1]	Transmission Congestion Relief[1]	T&D Upgrade Deferral[1]	Time-of-Use Energy Cost Management[1]	Demand Charge Management[1]	Electric Service Reliability[1]	Electric Service Power Quality[1]	Renewables Energy Time-shift	Renewables Capacity Firming	Wind Generation Grid Integration
Electric Energy Time-shift		●	◉	⊙*	◉	●	●†	●†	⊗	⊗	⊗	⊗	◉	◉	⊙
Electric Supply Capacity	●		◉*	⊙*	◉*	●	◉†	●†	⊗	⊗	⊗	⊗	⊙X*	⊙X*	⊗
Load Following	◉	◉*		⊙*	◉*	◉	⊙X	◉X*	⊙*‡	⊙*‡	⊗	⊗	⊙	⊗	⊗
Area Regulation	⊙*	⊙*	◉*		◉*	⊗	⊙X*	⊗	⊗	⊗	⊗	⊗	○	○	⊗
Electric Supply Reserve Capacity	◉	◉*	◉*	⊙*		●	⊙*	◉*	◉*‡	◉*‡	⊗	⊗	◉*	◉*	○*
Voltage Support[1]	●	●	◉	⊗	●		◉	●	◉‡	◉‡	◉‡	◉‡	◉#‡	◉#‡	⊗
Transmission Congestion Relief[1]	●†	◉†	⊙X	⊙X*	⊙*	◉		◉X†	◉†	◉†	○	⊗	◉#	◉†	⊗
T&D Upgrade Deferral[1]	●†	●†	◉X*	⊗	◉*	●	◉X†		◉†	◉†	○	⊗	◉#	◉†	⊗
Time-of-Use Energy Cost Management[1]	⊗	⊗	⊙*‡	⊗	◉*‡	◉‡	◉†	◉†		●†	●	●	◉#	◉†#	⊗
Demand Charge Management[1]	⊗	⊗	⊙*‡	⊗	◉*‡	◉‡	◉†	◉†	●†		●	●	◉#	●†#	⊗
Electric Service Reliability[1]	⊗	⊗	⊗	⊗	⊗	◉‡	○	○	●	●		●	◉#	◉#	⊗
Electric Service Power Quality[1]	⊗	⊗	⊗	⊗	⊗	◉‡	⊗	⊗	●	●	●		⊗	⊗	⊗
Renewables Energy Time-shift	◉	⊙X*	⊙	○	◉*	◉#‡	◉#	◉#	◉#	◉#	◉#	⊗		●	⊙X
Renewables Capacity Firming	◉	⊙X*	⊗	○	◉*	◉#‡	◉†	◉†	◉†#	●†#	◉#	⊗	●		⊙X
Wind Generation Grid Integration	⊙	⊗	⊗	⊗	○*	⊗	⊗	⊗	⊗	⊗	⊗	⊗	⊙X	⊙X	

Notes

a. For Area Regulation: Assume that storage cannot be connected at the distribution level.

b. For Voltage support: Assume that a) storage is distributed and b) the storage system includes reactive power capability.

c. For Reserve Capacity: Must have stored energy for at least one hour of discharge (i.e., so can offer useof the storage as reserve capacity on "hour-ahead"

d. For T&D Load Following: For load following up (mornings) or down (evenings) involving charging; must pay prevailing energy price.

e. For T&D Deferral: Annual hours of discharge range from somewhat limited to none. So storage is available for other applications during most of the year.

f. For Time-of-use Energy Cost Management and Demand Charge Management: Assume discharge for 5 hrs./day (noon to 5:00 pm), weekdays, May to Octo

g. Transmission Support (not shown) is assumed to be mostly or entirely incompatible with other applications.

Annotations

[1]Requires distributed storage that is located where needed.

x Somewhat to very circumstance-specific, especially regarding timing of operation and/or location.

* Most storage cannot provide power for both applications simultaneously.

† Presumably discharge is somewhat to very coincident for the two applications.

For distributed storage: charging energy a) from onsite renewable generation and/or or b) purchased from offsite renewable generation via the grid.

‡ Requires utility dispatch of onsite storage.

6.2. Benefits Aggregation Challenges

There are some notable challenges associated with benefits aggregation. One important theme in that regard is that much of the knowledge, perspective and experience needed for savvy and effective benefit aggregation are yet to be acquired because benefit aggregation is just becoming common practice. Given that premise, significant education and research are needed to provide important evidence to key stakeholders, especially utility regulators and utility engineers and financial decision-makers, about the merits and importance of benefits aggregation.

The following (listed in no particular order) are some of the reasons that benefit aggregation is challenging and not common practice:

- The potential for technical and/or operational conflicts.
- Regulatory ‘permission’ does not exist.
- Engineering standards and tools do not exist.
- Weak or non-existent price signals make it difficult for some stakeholders to internalize some/many benefits. In other words, inefficient markets.
- Prevailing utility technological and financial biases against any untested or unfamiliar solution, and consequently, the slow pace of change in the utility industry.
- Some storage benefits have been demonstrated insufficiently or not at all.
- The benefits that do exist tend to be difficult to aggregate in practice because, for example, different benefits accruing to several stakeholders must be coordinated for a given value proposition to be financially attractive and operationally viable.

6.2.1. Technical Conflicts

In some cases, storage systems do not have the features or performance characteristics needed to serve multiple applications. One example is storage that cannot tolerate many deep discharges. Such storage systems could be well-suited for T&D deferral because storage might be used infrequently for that application, but the same storage system is not suitable for energy time-shift, which requires a lot of charging and discharging.

Another example is storage that cannot respond rapidly to changing conditions. Such systems may be suitable for energy time-shift or to reduce demand charges, but they may not be able to provide transmission support or end-user power quality benefits.

Another important criterion affecting technical compatibility is the storage’s discharge duration. Storage whose discharge duration is optimized for some applications may not have enough discharge duration to serve other applications. Additionally, less reliable (though lower cost) storage systems may be suitable for energy time-shift or TOU energy cost reduction benefits; however, such systems could not be used for demand reduction, T&D support, or T&D deferral benefits because those applications require high reliability for the benefits to accrue.

6.2.2. Operational Conflicts

When estimating combined benefits for a value proposition, it is important to consider all potential operational conflicts between the applications being combined. Operational conflicts involve competing needs for a storage plant's power output and/or stored energy. For example, when storage is providing power for distribution upgrade deferral it cannot be called upon to provide backup power for electric service reliability. Another example is storage that is being used for most types of ancillary services: That same storage cannot be used for most other applications (*e.g.,* electric energy time-shift or transmission congestion relief) at the same time.

6.2.3. Aggregating Benefits among Stakeholders

One of the biggest challenges for many otherwise financially attractive value propositions is aggregating benefits that accrue to different stakeholders. Specifically, many of the benefits described in this report accrue to specific electricity end users, some to the ratepayers as a group, and others to utilities. Furthermore, various benefits accrue to different utility subsidiaries (*e.g.,* electric supply, transmission, distribution, customer service and unregulated business activities) that do not necessarily have the same incentives or biases.

Five 'beneficiary stakeholders' are worth noting because most benefits accrue to them: 1) specific electricity end users (*e.g.,* those who use storage to reduce electricity cost); 2) utility ratepayers at large; 3) the utility, especially T&D and electric supply business units; 4) 'merchant' storage project owners (*i.e.*, entities that use storage for profit only); and 5) society at large (*e.g.*, for improved environmental quality). In addition to the beneficiary stakeholders, there may other stakeholders with which aggregators must *coordinate* including regulators, ISOs, permitting agencies, and affected localities/communities.

Consider storage for T&D deferral. Utility ratepayers would be better off if the cost incurred per kWh of energy delivered is reduced, as would be the case with cost-effective T&D deferral. Nevertheless, in some circumstances ratepayers' interest may be at odds with investor-owned utilities' need to invest in *equipment* to generate dividends. (Recall that IOUs do not make any profit from mark-up on energy or fuel purchases, rather energy and fuel purchases are treated as 'pass-throughs' meaning that the utility passes the cost for energy on to end users without any mark-up or profit.)

Similarly, in some circumstances, specific electricity end users that install storage to reduce TOU energy cost and/or to reduce demand charges may actually reduce revenues needed to cover the utility's carrying cost for investments in generation and/or T&D equipment.

Consequently, when aggregating benefits into a value proposition, it is important to acknowledge and address the 'cross-cutting' nature of storage value propositions and the diversity of topics, stakeholders, motivators, and incentives that must be considered when developing or pursuing an actual project involving an electric utility-related energy storage value proposition.

Section 7.1 provides some additional details about important stakeholders and Section 7.2 provides an introduction to important challenges that may affect prospects for benefits aggregation.

6.2.4. Effect on Market Potential

As described in Section 4, it is important to consider the effect on market potential when combining applications. The market potential for specific combinations is almost certainly not the sum of the market potential for individual applications.

6.3. Notable Application Synergies

Each application characterization in Section 3 included a summary of notable synergies with other applications. A few application synergies in particular stand out within the context of developing attractive value propositions.

6.3.1. Electric Energy Time-shift and Electric Supply Capacity

Although it is important to maintain a crisp distinction between capacity-related and energy-related applications (and benefits), there are important synergies between the two. Those synergies exist if use of energy and need for capacity occur concurrently (which is fairly common). For example, storage used by an end user to reduce TOU energy charges could also reduce the same end user's demand charges; provide dispatchable load control as a system resource; or reduce loading on T&D capacity to reduce congestion or for T&D deferral. Another example is storage used for electric energy time-shift. It can provide electric supply capacity benefits because the times when energy has a high value coincide with high capacity value.

6.3.2. Electric Supply Reserve Capacity

Electric supply reserve capacity is especially compatible with other application/benefit combinations. (See Section 3.3.3 for details.) The most important reasons are 1) most times storage is used for reserves,so it may not have to discharge; 2) storage can provide two times its power as reserve capacity while charging; and 3) if there is an hour-ahead market for reserve capacity, then decisions can be made almost in real-time regarding the merits of discharging (if needed) *versus* saving the energy for later, for more benefit.

6.3.3. Load Following

Load following is somewhat compatible with storage used for other applications, primarily because storage can provide load following (up or down) while charging. (See Section 3.3 for details.) So, while storage is being charged (so that it can serve one ore more other applications), the same storage can provide load following.

6.3.4. Transmission and Distribution Upgrade Deferral

The T&D upgrade deferral application (and the closely related T&D life extension application), may be compatible with several applications. Probably the most important consideration is that storage used for T&D deferral or life extension is needed for just a few tens of hours to perhaps 200 hours per year. Consequently, storage can be used for other applications for as much as 95% of the year. And, in most cases storage discharge for T&D deferral or life extension is likely to occur when the energy and the capacity are both valuable from an electric supply perspective. Similarly, depending on the location, the same storage could also be used for transmission congestion relief.

6.3.5. Demand Charge Management and Time-of-use Energy Cost Management

Storage used to manage TOU energy cost and/or demand charges could provide other important benefits. First, the same storage used for those purposes could also be used to improve on-site electric service reliability and/or power quality. Also, if the storage is located in a part of the T&D system that is heavily loaded during peak demand times, then the same storage could also provide benefits for T&D upgrade deferral or life extension. Similarly, the same storage could be used to reduce transmission congestion, if the storage is located downstream from congested parts of the transmission system. The same storage could also provide electric service reserve capacity during much of the year.

6.3.6. Electric Service Reliability and Electric Service Power Quality

Presumably, storage used to improve electric service reliability and/or electric service power quality would have a discharge duration of a few minutes to perhaps an hour. Consequently, storage used for those applications may not be suitable for many other applications. Storage deployed mainly for *other* applications, however, may be well-suited for improving reliability and/or power quality if a modest amount of storage is added to provide additional discharge duration relative to the discharge duration needed for the other application(s).

6.4. Distributed Energy Storage

Because *distributed* energy storage can be used for more applications than larger, central storage, distributed storage may be used for a broader spectrum of value propositions.

It is important to distinguish between locational benefits and non-locational benefits. Locational benefits are those that can be realized only if distributed storage is deployed where needed. Non-locational benefits can be realized regardless of distributed storage's location.

6.4.1. Locational Benefits

Locational benefits include transmission congestion relief, T&D upgrade deferral, TOU energy cost management, demand charge management, electric service reliability, and electric service power quality. Additionally, the way voltage support is defined in this report, storage used for voltage support should be located close to inductive loads. Depending on the circumstances, benefits for renewables energy time-shift and renewables capacity firming also may be locational, if for example, the renewable energy generation is distributed (*e.g.*, photovoltaics).

6.4.2. Non-locational Benefits

Non-locational benefits that can accrue if distributed storage is used include electric energy time-shift, electric supply capacity, load following, and electric supply reserve capacity. Depending on the circumstances, benefits for renewables energy time-shift and renewables capacity firming may be non-locational, if for example, the renewable energy generation is deployed in large wind farms or solar thermal generation that is remote to load centers.

6.5. Storage Modularity

As described in Section 2.14, to one extent or another, most storage technologies can be deployed as relatively small modules. Some storage technologies (especially batteries, capacitors and, to a lesser extent, flywheel storage) are inherently modular. Although normally considered to be suitable for large single-site storage projects, even above-ground CAES and small pumped hydroelectric storage could be modular (though above-ground CAES and pumped hydroelectric 'modules' are probably larger than those of other modular storage technologies.)

Use of modular electric resources (including electricity storage) could lead to a profoundly different electric utility capacity expansion philosophy than that which prevailed during the previous century because smaller, modular resources offer more diverse, robust, and optimizable approaches *versus* the 'limited and lumpy' options used in the past. Furthermore, modular resources can be used for a wider array of applications than larger, less modular options.

Importantly, smaller, more modular resources tend to be more expensive (per kW, and for storage, per unit of discharge duration). Further, in many cases, more modular resources are less energy efficient.

The following notable considerations that are specific to *modular* distributed storage are described below:

- Optimal Capacity Additions
- T&D Planning Flexibility
- Unit Diversity
- Resource Aggregation
- Transportability

6.5.1. Optimal Capacity Additions

One of the most attractive aspects of modularity is that capacity can be added incrementally, where and as needed (*i.e.*, for 'just-in-time' capacity). Modularity may also enable cost-effective redeployment of storage capacity. For utilities, modularity (and redeployment) may reduce both the total cost of service for and the risk associated with larger, more 'lumpy' investments in infrastructure (*e.g.*, T&D capacity additions).

6.5.2. T&D Planning Flexibility

One important feature of any modular resource, including storage, is that it allows for more flexible responses to challenges than are possible using the limited number of conventional utility solutions. (See Section 5.3.9 for more about flexibility.)

6.5.3. Unit Diversity

One reason to use modular electricity resources is that the aggregate capacity from those resources is probably more reliable than the aggregate capacity provided by larger, less modular resources because, at any time, only one module (or at most a few modules) is likely to be unavailable for service, so the resources' aggregate capacity is only minimally affected. In contrast, the failure of a single or less diverse resource means that all or a significant portion of the resource's capacity is unavailable to serve load.

6.5.4. Resource Aggregation

For value propositions involving residential or small-to-medium commercial end users, the effort required to investigate, analyze, design, purchase, install, and operate storage and other modular electricity resources (including demand response, distributed generation, and PHEVs) is a significant and possibly expensive challenge. In those circumstances, load aggregators – or more generally, electric *resources* aggregators – may be positioned to address many of the administrative, legal, and regulatory challenges on behalf of owners of many small individual resources.

6.5.5. Transportability

Modular energy resources (including storage) that can be moved somewhat-to-very easily may be used in two (or more) locations at different times. This feature is especially attractive if the challenges addressed with the transportable resources tend to be transitory (*i.e.*, lasting just one or a few years). Thus, transportable storage used to address a challenge at one location in a given year may be relocated to address a similar or different challenge at another location, in a subsequent year. In fact, transportable storage could even be used at two different locations in the same year if the locations' challenges occur during different seasons.

Consider a realistic example: Transportable storage used 1) at one location with a sharp, but infrequent, summer peak caused by residential air conditioning loads, and 2) at another location that has demand peaks during winter driven by heating loads. Transportability is also attractive for locations where capacity or energy needs change from one year to the next.

6.6. Value Proposition Examples

This section includes a characterization of possible value propositions involving combinations of technically and operationally compatible applications. Importantly, these are just a few of the possible combinations. Not included are value propositions that are technically incompatible (*i.e.*, the application-specific storage needs are different).

6.6.1. Electric Energy Time-shift Plus Transmission and Distribution Upgrade Deferral

One notable application combination is electric energy time-shift plus T&D deferral. In many, (and perhaps most) cases, localized T&D peak demand coincides with 'system' (supply and transmission) peak demand periods. Consequently, it is likely that the energy discharged while storage is serving the T&D upgrade deferral application has a high value. Furthermore, in most cases, storage used for T&D upgrade deferral discharges for a very small portion of the year, if at all. So, storage used for T&D upgrade deferral during a small number of hours/days per year can also provide electric energy time-shift-related benefits during almost the entire year. Even if storage does not provide T&D upgrade deferral benefits in any given year, it can still be used for electric energy time-shift (and possibly other applications such as electric supply reserve capacity).

6.6.2. Time-of-use Energy Cost Management Plus Demand Charge Management

Many, and perhaps most, electricity end users who pay demand charges also pay TOU energy prices. Demand charges are most common for larger, non-residential end users, although that may be changing. An attractive scenario for this value proposition may be indicated by a combination of high on-peak demand charges, high on-peak energy prices, low or no off-peak or 'facility' or 'baseload' demand charges, and low off-peak energy prices.

6.6.3. Renewables Energy Time-shift Plus Electric Energy Time-shift

It is often suggested that energy storage could be used to significantly increase the value of renewables' intermittent output. In many cases, however, the incremental benefit may not be commensurate with the incremental cost of the storage plant. Another possibility is a project involving use of storage to time-shift energy from intermittent renewables *and* to time-shift wholesale electric energy from the grid. The same storage could even be physically decoupled from the generation and located where other benefits may accrue as well. For example, storage used to time-shift energy from wind generation and to time-shift energy from the grid could provide transmission support or even, conceivably, a T&D upgrade deferral benefit, depending on the storage system's location.

6.6.4. Renewables Energy Time-shift Plus Electric Energy Time-shift Plus Electric Supply Reserve Capacity

Depending on circumstances, the same storage used for the value proposition described above (renewables energy time-shift plus electric energy time-shift) could also be used for electric supply reserve capacity. When the storage is charged and idle, it could provide reserve capacity. When it is charging, the storage could provide 2× its rated power as reserve capacity. It is even conceivable that storage could provide load following and provide reserves while charging if charging occurs during times when load is picking up (usually in the morning) and/or when load is dropping off (usually in the evening).

6.6.5. Transportable Storage for Transmission and Distribution Upgrade Deferral and Electric Service Power Quality/Reliability at Multiple Locations

For this value proposition, transportable storage is used at ten different locations for either T&D upgrade deferral or to improve electric service power quality and/or electric service reliability. The benefit for T&D upgrade deferral is assumed to be $367/kW-year of storage, and the benefit assumed for electric service power quality/reliability is $75/kW-year of storage.

Consider this hypothetical scenario: Transportable storage is used at five different locations for one year of T&D upgrade deferral at each location, in alternating years. In the other five years, when the storage is not used for T&D upgrade deferral, it provides a benefit related to improving local electric service power quality and/or electric service reliability. The benefits for that scenario are shown in Figure 20. As shown in the figure's right-side Y-axis, the present worth of the annual benefit is nearly $1,700/kW of storage. So, if storage can be owned and operated for less than $1,700/kW, for 10 years, then it would be a financially attractive option. That value would provide a helpful target for lifecycle cost for modular electric energy storage (in this case, with a 10-year life).

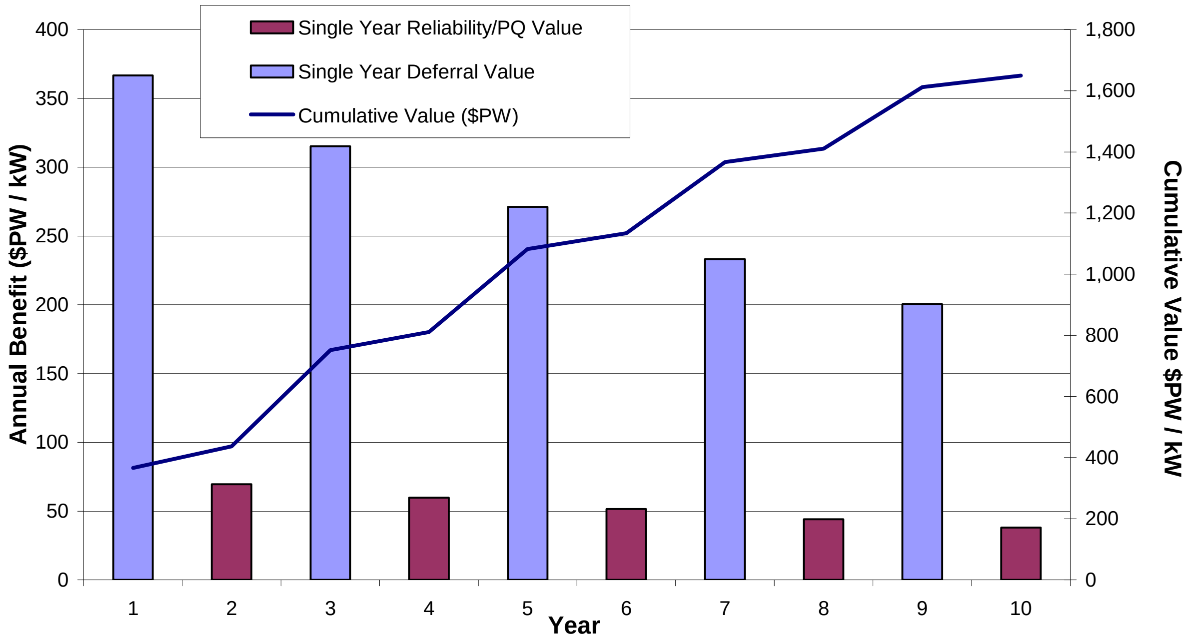


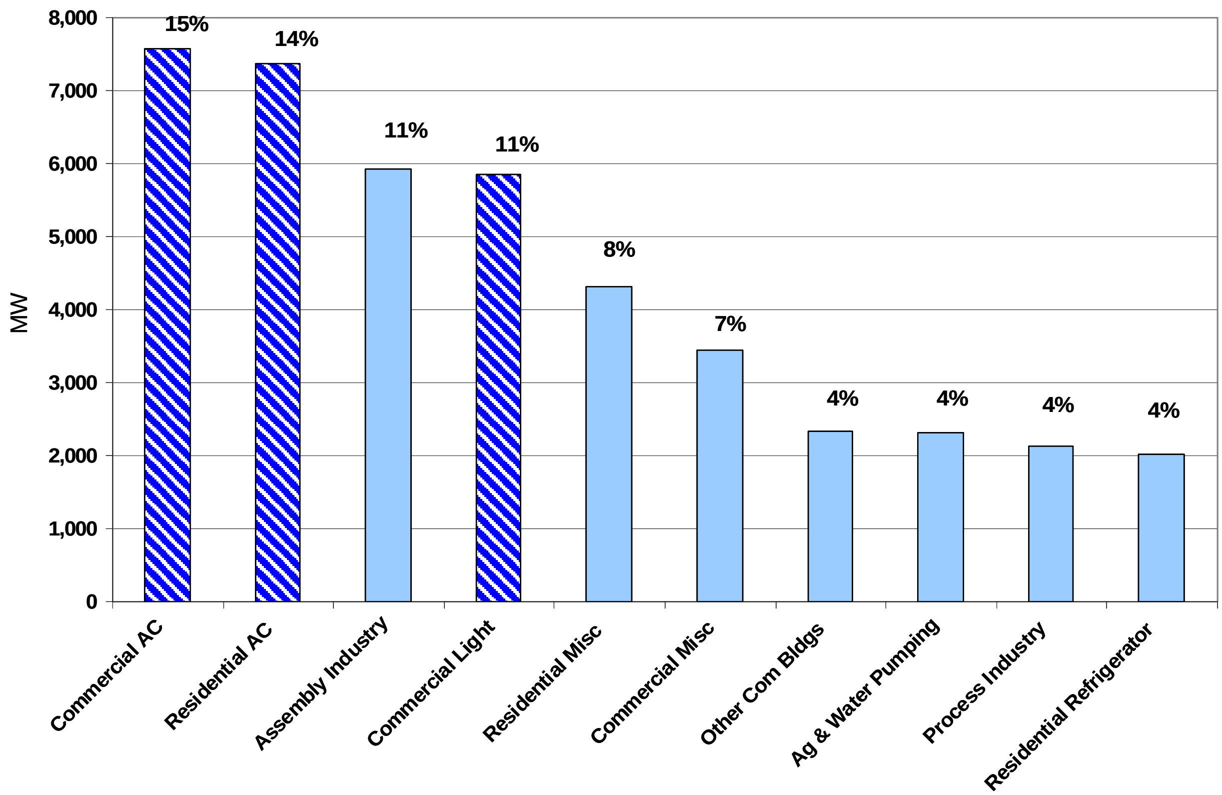
Figure 20. Value proposition for transportable storage.

6.6.6. Storage to Serve Small Air Conditioning Loads

Using storage in conjunction with smaller air conditioning (A/C) units, especially residential and small commercial 'package' units, could be the basis for a compelling value position, for several reasons, most importantly 1) A/C loads comprise a significant portion of peak demand, 2) many A/C loads only operate for a few hundred hours per year, 3) small A/C motors pose an especially difficult challenge during grid-wide voltage emergencies that can exacerbate regional power outages, and 4) storage used to serve air conditioning loads could be available for most of the year for other benefits.

In many regions, A/C comprises a significant portion of peak demand. While circumstances are different in each region, based on the values shown in Figure 21, A/C accounts for 30% of summer peak demand in California. Note also that about 53% of all A/C-related demand in California is for commercial electricity users and about 47% of A/C-related demand is for residences.[82]

Given A/C's significant contribution to peak demand, utilities may incur a substantial A/C-related capacity cost – for generation, transmission, and distribution equipment to serve A/C load, but most A/C – especially small residential and commercial units – is operated for relatively few hours per year. The primary effect is that the utility receives relatively little annual revenue per kW of small A/C load served when compared to other common load types. So, smaller A/C loads cost a lot to serve (per kW) because they require so much capacity (equipment) even though limited use of small A/C equipment leads to low revenues (per kW). The consequence is very poor asset utilization.



Source: California Energy Commission.[83]

Figure 21. Components of peak electric demand in California.

6.6.6.1. Storage for Air Conditioning: Increased Utility Asset Utilization

The concept of poor asset utilization is illustrated graphically by the load duration curve (LDC) in Figure 22 and Figure 23. An LDC is a plot of hourly demand values, usually for one year, arranged in order of magnitude, irrespective of which hour during the year the demand occurs. Values to the left represent the highest levels of demand during the year, and values to the right represent the lowest demand values during the year.

The LDC in Figure 22 represents hourly load on a part of a distribution system during a specific year. Figure 23 includes only the highest 2% of demand values from those shown in Figure 22. The LDC shown, though real, represents a relatively extreme case (*i.e.*, the ratio of peak demand to average demand is unusually large). It was chosen because it illustrates well the concept of poor asset utilization. Specifically, as shown in Figure 23, 10% of the annual maximum demand occurs during about 0.4% of the year. Importantly, a significant portion of that demand is from A/C loads.

Storage use could increase asset utilization by reducing or eliminating the need for capacity, on the margin, and by providing charging energy for the storage during off-peak hours when generation, transmission, and distributions assets are usually underutilized.

Depending on the location and circumstances, storage serving smaller A/C loads could reduce the need for generation and T&D capacity and could lead to increased utilization of existing equipment (assets). It is likely that an energy time-shift benefit will also accrue incidentally.

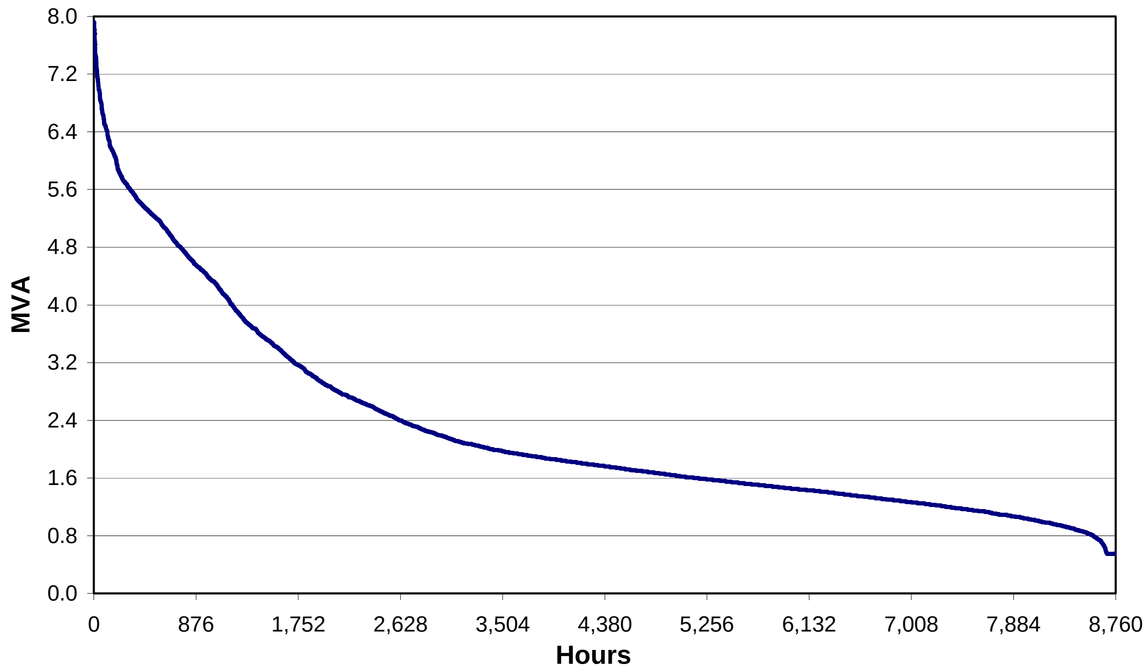


Figure 22. Load duration curve for an electricity distribution node.

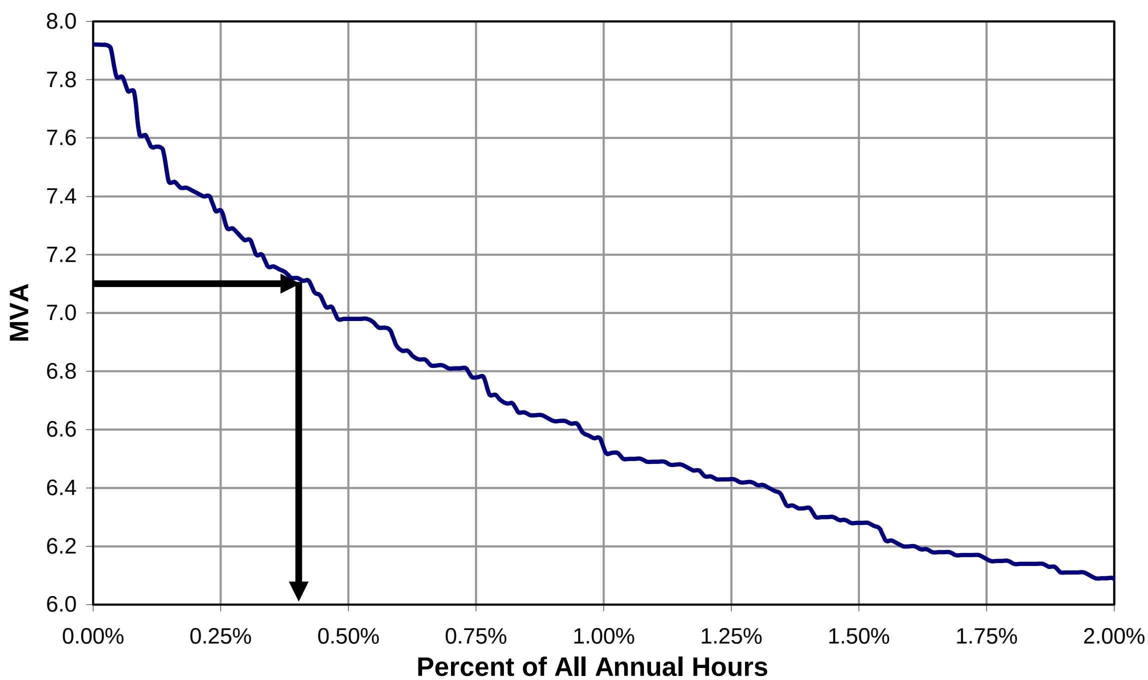


Figure 23. Portion of load duration curve with highest values.

6.6.6.2. Storage for Air Conditioning: Voltage Support

The voltage support benefit is notable because, as described in Section 3.3.4, small A/C motors pose a considerable challenge during grid emergencies by drawing additional current as voltage drops. This can pose a relatively significant challenge as the grid is re-energized after outages. Additionally, conventional capacitors used to manage localized voltage drops (due to reactance) under normal circumstances do not perform well as voltage support resources.

Consider one operational scenario: Distributed storage is used to serve small A/C equipment under normal grid conditions. If there is an 'electric supply emergency,' then the storage responds like other demand response resources by turning off the A/C equipment and providing power to the grid. If the storage's PCU has reactive power capability then the storage system could also provide reactive power as described in Appendix C.

Assuming that storage is located at or near A/C loads, the storage could provide several other important benefits, including at least two *non-locational* benefits: electric supply reserve capacity and load following. Additionally, *locational* benefits could include transmission congestion relief; improved electric service reliability and/or localized electric service power quality; and localized voltage support. Storage for smaller A/C loads could also be an important element of a robust Smart Grid and/or demand response implementation. The storage could also be used for wholesale or renewables energy time-shift on days that it is not needed for A/C loads.

One technical challenge is the amount of in-rush current needed for A/C compressor motor startup. Storage system PCUs may not be capable of providing the in-rush current needed. One way to address that issue is by using a hybrid storage system with two types of storage: one type that can provide high power for short durations, such as capacitors, and another that provides nominal power for long durations. Another possibility is to use the grid to provide some or all of the current during compressor motor startup (only during normal operating conditions for the grid). Given the diversity of compressor motor startups, presumably, providing in-rush current would not have an adverse affect on the grid.

Note that utility thermal energy storage incentives and programs are justified based on some of the same benefits described above primarily reduced demand for generation *capacity* and reduced cost for on-peak *energy* and, possibly, for reduced need for transmission capacity.

6.6.7. Distributed Storage *in lieu* of New Transmission Capacity

Distributed energy storage could be one important response to expected transmission capacity shortfalls. The need for new transmission capacity is driven by increasing peak demand and on-peak electric energy use; increasing interconnectedness of the grid and use of interregional generation resources; and increased deployment of renewable energy generation. Storage could help if it is located near load centers and charged during off-peak times, usually at night, when transmission systems are not heavily loaded; T&D I^2R energy losses are relatively low; and energy price tends to be low.

During on-peak times storage is used to serve load, reducing the amount of power used during peak demand periods, thus reducing loading on the transmission equipment. Four primary benefits of such use are 1) reduced need and cost for transmission capacity, 2) increased transmission asset utilization, 3) reduced T&D energy losses, and 4) energy time-shift. Of course, because the storage is distributed it could also be used for other locational benefits.

6.6.8. Distributed Storage for Bilateral Contracts with Wind Generators

In many areas, a significant portion of wind energy is produced at night when the energy's value is relatively low. Additionally, at some times of the year the supply of electric energy being generated exceeds demand for energy. One possible way to make better use of that energy is to use it to charge distributed storage.

Although several possible transactional frameworks could be used, one involves a bilateral contract between wind energy vendors and storage owners. Of course, either of those parties could use agents such as aggregators. Several benefits are possible using such a framework. The storage owner could use the storage to manage energy and demand charges or to enhance electric service reliability and/or power quality. Depending on the circumstances, distributed storage could reduce congestion of *existing* transmission capacity or delay or reduce need for *new* transmission capacity.

6.7. The Societal Storage Value Proposition

Although many benefits can be partially or totally internalized by the storage owner/user; an important factor that affects prospects for increased storage use is that some notable benefits accrue – in part or in whole – to utility customers as a group and/or to society at large. That leads to the compelling concept of a societal value proposition for storage.

The storage-related societal value proposition may include, but is not limited to, the following benefits (presented in no particular order):

- Reduced need for equipment and land for on-peak generation and transmission capacity.
- Increased asset utilization of existing utility generation, transmission, and distribution.
- Enabling superior operation of the existing generation fleet (*i.e.,* dynamic operating benefits) and transmission capacity.
- Reduced reliance on fossil fuel and increase energy security.
- Reduced air emissions.
- Reduced transmission and distribution energy losses.
- Enabling superior renewables integration to optimize benefits and to reduce integration cost and challenges.
- Enabling superior value from Smart Grid.
- Reduced cost-of-service (*e.g.,* by energy time-shift).
- Improved business productivity due to improved electric service reliability and power quality.
- Reduced need and cost for and extraction and refining of key commodities that would be needed to build conventional electric utility capacity; primarily, steel, aluminum, and copper.

The societal value proposition is an important consideration given the significant role that storage could and should play in the electricity marketplace of the future. Stakeholders that may need to understand and to consider the societal value for storage include existing and prospective storage beneficiaries, such as electric utilities and their customers; electric utility regulators; energy and electricity policymakers and policy analysts; and storage advocates.

Robust consideration of the societal value proposition for storage is important for reasons similar to those that drive the need to consider the societal value proposition for energy efficiency, demand response, distributed resources, and renewables. Perhaps the most important reason is that although the cost for storage may exceed the *internalizable* benefits, the cost may be lower than the combined value of internalizable benefits plus societal benefits. (See Section 1.4.2 which addresses the concept of internalizable benefits.)

It is important for lawmakers, regulators, and policymakers to be inclusive as they develop, consider, and promulgate regulations and policies whose outcomes/results could be improved if storage is used. For example, relevant decision-makers should consider the ways that storage could improve prospects for success regarding environment, energy, and electricity-related policy objectives such as increased use of renewables and reduced need for transmission infrastructure.

Similarly, it is important to consider incidental/unintended negative effects that laws, regulations, and policies may have on prospects for increased storage deployment. Consider an example: Many utilities do not have ‘regulatory permission’ to own distributed/modular resources (especially storage and generation) even though those alternatives may afford a superior means to serve load on the margin, *vis-à-vis* conventional ‘lumpy’ capacity additions, especially T&D capacity. (See Section 3.4.3 for more details.)

Finally, the societal value proposition may overlap with, and may be somewhat or even very coincidental to, an owner/user storage value proposition that involves direct/internalizable benefits. Consider a storage owner that uses storage to reduce on-peak TOU energy cost and peak demand charges. In that example, some societal benefits could include reduced land use impacts associated with reduced construction of new generation and transmission capacity; improved utility asset utilization; reduced air emissions; and improved business cost competitiveness.

7. Electricity Storage Opportunity Stakeholders, Challenges, and Drivers

This section presents potentially important topics and factors to consider when evaluating prospects for storage. Included are lists of the following: possibly important stakeholders, important challenges facing prospective storage users and developers, and notable storage opportunity drivers. Also included are brief characterizations of several important developments that could be significant drivers of many attractive electric utility-related storage opportunities:

- Increasing recognition by lawmakers, regulators, and policymakers of the important role that storage should play in the electricity marketplace of the future
- Increasing sophistication and savvy of load and distributed resource aggregators
- Increasingly rich price signals for electric utility-related services
- Tax and regulatory incentives
- Growing transmission capacity constraints
- Expected proliferation of PEVs and PHEVs
- Increased use of intermittent renewables
- Increasing focus on distributed resources
- Need to reduce generation fuel use and air emissions
- Innovation that drives improvements to storage technology and storage subsystem technologies
- An increasingly 'smart' grid that enables effective integration of some renewables and integration and dispatch of distributed resources including demand response, generation and storage

7.1. Stakeholders

There is a wide range of possible stakeholders in the electric-utility-related electricity storage opportunity. Of course, not all possible storage uses or projects must accommodate all of the stakeholders. The importance of particular stakeholders varies depending on factors such as the application(s), storage size and type, region, the utility or utilities involved. So, it is important to be familiar with the spectrum of possible stakeholders when formulating or evaluating value propositions.

Key 'beneficiary stakeholders' (*i.e.,* parties that derive benefit from storage) include the following:

- Specific ratepayers that use storage to reduce electricity cost
- Utility ratepayers at large (if storage reduces the *utility's* overall cost-of-service which leads to reduced electricity price)
- Utilities

- ‘Merchant’ storage project owners (entities that use storage for profit only)
- Aggregators
- Storage equipment and services providers
- Society (*e.g.*, for improved environmental quality and economy)

Several important institutional or ‘gatekeeper’ stakeholders include the following:

- Engineering and standards community (*e.g.*, the American Society of Mechanical Engineers, the IEEE, the National Electrical Code, *etc.*)
- Federal and state energy/utility regulatory agencies
- Regional ISOs
- Local safety, siting, planning, and land use agencies
- Host communities

Other possibly important stakeholders include the following (presented in no particular order):

- Bill payers (often end users and bill payers are not the same people/entity)
- Utility functional entities (*e.g.*, electric supply, transmission, distribution, customer services, unregulated subsidiaries)
- Storage system integrators, project developers, architecture and engineering firms
- Politicians
- Electricity and environmental regulators
- Electricity, energy, and environment policymakers
- Electricity, energy, and environment researchers and research programs
- Smart Grid
- Independent power and energy services providers
- City and community planners and zoning officials
- Permitting agencies (*e.g.*, fire and health and safety)
- Landlords and property managers
- Storage advocates and advocacy organizations (*e.g.*, the Electricity Storage Association)
- Ratepayer and energy user advocacy groups
- Trade groups for specific industries and/or large commercial energy users

7.2. Challenges

To be sure, there are challenges that will affect efforts to site or deploy storage for many potentially attractive value propositions. Readers should be aware of those challenges when considering prospects for storage to be used for specific value propositions.

What follows is a summary list including some of the most important challenges that could face storage users and project developers as the storage opportunity unfolds. (See Appendix G for a more detailed list.)

- Storage's relatively high cost per kW installed
- Lack of storage-related regulatory rules and 'permission,' especially regarding distributed storage
- Prevailing electric energy and services pricing that are not economically efficient (though this is changing)
- Limited risk/reward sharing mechanisms
- Permitting and siting rules and regulations
- Limited familiarity, knowledge, and experience base (for storage)
- Existing utility technology biases
- Limited storage-related engineering standards and evaluation methodologies and tools
- Financing of *any* 'new' technology is challenging
- Investor-owned utility preference for investments in equipment and aversion to expense-based alternatives
- Inadequate infrastructure features and 'hooks' needed to accommodate or to optimize benefits from storage, especially distributed storage
- Competition among many technologies, concepts, and programs (*e.g.,* demand response, Smart Grid, distributed generation, renewables, *etc.*)
- Coordinating among numerous stakeholders, for 'permission' to use grid-connected storage and./or to aggregate benefits

7.3. Opportunity Drivers

The following is a list of possibly important drivers of the energy storage opportunity in the emerging electricity marketplace. Note that some of these drivers are also included in the list of *challenges*. The opportunity drivers identified by the authors include the following (in no particular order):

- Increasing interest in storage by politicians, regulators, and policymakers:
    - ☞ Battery development that is driven by automotive/transportation
    - For renewables integration
    - For transmission congestion relief and to reduce need for new transmission
- The emerging electricity marketplace:
    - Competition
    - Richer electricity-related price signals:
        - A general trend toward disaggregation of prices for energy and services

        - Locational prices
        - TOU prices
    - A broad range of new electric, control, and information technologies
- Increasing emphasis on intermittent renewable energy-fueled generation
- Generation and transmission capacity constraints and transmission congestion
- Existing and prospective incentives to install storage:
    - Tax-related issues
    - Regulatory/utility issues
    - ☞ Storage provides similar or even superior benefits to non-storage resources that are currently eligible for incentives (*e.g.*, end-use efficiency, demand response and distributed generation).
- Surging interest in electric vehicles, PEVs, and PHEVs:
    - ☞ Will affect grid cost and operations
    - ☞ Key impetus for battery technology improvements
- Growing use of demand response:
    - Especially *in lieu* of upgrading generation and transmission capacity
    - When energy is too expensive or not available
- Smart Grid
- Load aggregation
- The important role of independent power providers and energy services providers
- Growing emphasis on modular DER:
    - Distributed generation
    - Geographically targeted demand response and energy efficiency
    - Distributed energy storage
- Increasing emphasis on reducing air emissions from the electric supply
- NIMBY (not in my backyard) and BANANA (build absolutely nothing anywhere near the area):
    - Large-scale generation (conventional and renewables)
    - Transmission issues
- Growing preference for reduced fuel use
- Accelerating energy storage technology innovation (especially batteries, and to a lesser extent, capacitors and CAES)

7.4. Notable Developments Affecting Prospects for Storage

This section includes brief characterizations of ten important developments – mostly in the electricity marketplace – that could be especially important drivers of many attractive electric-utility-related opportunities for storage.

7.4.1. Smart Grid and Electricity Storage

In broad terms, the vision for the Smart Grid is to increase operational efficiencies; improve electric service reliability; increase utility customer retention; and optimize capacity expansion (generation, transmission, and distribution) asset utilization.

Smart Grid acts as a controlling mechanism for the Advanced Metering Infrastructure (AMI) and smart meters. AMI and smart meters, in turn, enable two-way communication between a utility and its customers. Consider one concrete example: Smart Grid is expected to reduce energy use and peak demand by providing rich price signals using real-time data about energy cost and generation, transmission, and distribution capacity constraints.

Among other characteristics, Smart Grid is expected to be 'continuously upgradeable'. Also, Smart Grid will be an important element of a 'self-healing' electricity T&D network. It will add flexibility as utilities accommodate load and energy use growth. Smart Grid will also provide improved means to manage electricity transmission and distribution. Smart Grid could also be used for reactive power compensation and voltage control which, among other benefits, increases the throughput of T&D equipment. In 2008, the U.S. Department of Energy Smart Grid Task Force established the following seven 'characteristics of Smart Grid':

1. Enable active participation by consumers.
2. Accommodate all generation and storage options.
3. Enable new products, services, and markets.
4. Provide power quality for the range of needs in a digital economy.
5. Optimize asset utilization and operating efficiency.
6. Anticipate and respond to system disturbances in a self-healing manner.
7. Operate resiliently against physical and cyber attacks and natural disasters.

In the future, distributed energy storage deployed as part of, or in coordination with, Smart Grid should enable many rich value propositions that could include a wide array of benefits, possibly including the following:

- Aggregation, integration, optimization and coordination of all types of DER
- Electricity price hedging
- Ancillary services (*e.g.,* electric supply capacity reserves, voltage support provided locally, load following, area regulation)
- Reduced transmission congestion
- T&D upgrade deferral and equipment life extension
- Electric supply fleet performance and operation optimization (*i.e.,* DOBs)

Learn more about Smart Grid by visiting the U.S. DOE's Smart Grid website: http://www.oe.energy.gov/smartgrid.htm.

7.4.2. Increasing use of Demand Response Resources

Demand response is becoming an important resource, especially as an alternative to adding peak generation capacity and, to a lesser extent, to reduce need for or congestion of transmission systems. A summary of the value of demand response from the Peak Load Management Alliance includes the following primary elements:

- Reducing supplier and customer risk in the market
- Providing better reliability for the electricity system
- Reducing the costs associated with generation, transmission, and distribution
- Creating efficient markets
- Reducing environmental impact by reducing or delaying new power plant developments

7.4.3. Load Aggregators

The CAISO defines load aggregators as "…, a municipality or other governmental entity, an energy services provider, a scheduling coordinator, a utility distribution company, or any other entity representing single or multiple loads for the purpose of providing demand reduction service to the ISO."[84]

So, a load aggregator is any entity that combines loads into what is, in effect, a 'block' that can be controlled in response to requests by the ISO. Specifically, the ISO can rely on those blocks almost as if they are dispatchable generation capacity. That is, when there is not enough electric supply capacity available to serve all demand or to provide all necessary ancillary services, the ISO can request that the demand associated with load blocks be reduced or turned off.

A few points are worth considering. First, presumably, the scope of load aggregation could increase to include distributed generation and distributed storage. Although load aggregation tends to be done in response to electric-supply-related challenges, it seems likely that load aggregation could also be used to address more location-specific challenges such as overloaded T&D equipment or power-quality-related needs. It also seems likely that there could be some or perhaps significant convergence of Smart Grid, demand response, and load aggregation. Some of the advantages load aggregators have relative to individual end users, or perhaps even energy storage project developers, include the following (in no particular order):

- General business savvy regarding electricity value, pricing and markets
- Existing infrastructure
- Market familiarity
- Unit diversity
- The means to finance storage
- Opportunities to internalize more benefits

7.4.4. Increasingly Rich Electricity Price Signals

Another important development is the use of price signals for an increasing array of electric capacity, energy, and services that provide storage owners with the means to internalize more benefits. At least three important conventional pricing programs have existed for many years. As described in Section 3.5.1, some residential and many commercial electricity end users are eligible or even required to pay TOU-based prices for electric *energy*. Also, as described in Section 3.5.2, some electricity end users with somewhat large demand (>50 kW to 100 kW) often pay demand charges based on peak *load* and TOU charges for *energy*.

Many end users with medium demand or higher (>100 kW) are eligible for interruptible or curtailable rates. Under those rates, participating end users pay a discounted price for energy, and in return, the utility or the ISO may interrupt or curtail service, during grid emergencies, for a specified number of times, for specified durations. The interruptible or curtailable load is usually treated and used like reserve capacity for the electric supply system.

A more recent development is the establishment of critical peak pricing (CPP) for retail end users. Under terms of critical-peak-pricing tariffs, the utility can charge ‘very high’ prices for each kWh of energy used during critical peak periods. CPP tariffs allow the utility to impose the high prices a specified maximum number of times per year and for specified durations. In the U.S., the ISOs have implemented open markets for several ancillary services, including public posting of prices.

An emerging trend is the use of locational pricing or locational marginal pricing to better reflect the cost associated with delivery to specific parts of the grid. Among other factors, locational marginal prices could reflect area-specific energy cost/price, transmission capacity cost or charges, transmission congestion charges, and transmission I^2R energy losses. Importantly, load aggregators, Smart Grid, and demand response programs could be important enablers of a significant market for storage benefits when coupled with rich price signals.

7.4.5. Tax and Regulatory Incentives for Storage

One possibly important development for prospective energy storage purchasers and users is increased interest in providing related tax and regulatory/utility incentives. Tax incentives are most likely to include accelerated depreciation and possibly tax credits. Regulatory/utility (regulatory) incentives are most likely to include rebates that offset a portion of the purchase price. Although the analogy is not perfect, there is a lot of emphasis on providing tax and regulatory incentives for energy conservation and efficiency, peak demand reduction, and renewable energy systems.

Such incentives are currently offered for the following: purchasing and installing equipment for thermal energy storage; A/C efficiency improvements and/or downsizing; improving commercial lighting efficiency; installing distributed generation (*e.g.*, the Self-Generation Incentive Program in California); and/or installing renewable energy generation.

All of these programs are deemed to be important, at least in part, because they reduce peak demand, which reduces the need for electricity supply and T&D infrastructure. They also reduce on-peak energy use, which reduces fuel and operation cost for inefficient and expensive-to-run generation. It seems logical to at least consider incentives for using energy storage to the extent that it provides similar benefits.

7.4.6. Transmission Capacity Constraints

The need for additional transmission capacity is driven by several factors, including increasing deployment of bulk renewables generation that is located away from load centers; increasing the interconnectedness of the grid; increasing the use of non-utility-owned generation; increasing the use of generation located away from load centers, including increasing reliance on inter-regional energy transactions; increasing peak demand for electricity; and a heavily loaded and aging transmission infrastructure.

Importantly, storage could be used to reduce or to avoid the need for new, high-voltage, bulk transmission upgrades. That is important because one of the emerging challenges facing the new utility marketplace is the need for additional transmission capacity. Not only is *existing* transmission capacity getting older and less adequate, but siting *new* transmission is increasingly contentious.

While not addressed explicitly in this report, an approach similar to the ones used to estimate the T&D upgrade deferral benefit or T&D congestion relief benefit could also be used to estimate the benefit associated with avoided need for transmission. In simple terms, the benefit is related to the avoided cost for constructing new transmission capacity and/or upgrading existing equipment or regional transmission congestion charges.

7.4.7. Expected Proliferation of Electric Vehicles

Although the implications for energy storage generally are somewhat unclear, the expected proliferation of plug-in electric vehicles (PEVs) and plug-in hybrid electric vehicles (PHEVs) could have a significant impact on the potential for utility-related storage.[85] One possibility is that purchases of off-peak energy to charge storage will increase off-peak energy prices enough to reduce the benefit for some uses of utility-related storage, especially energy time-shift and TOU energy cost reduction.

Consider also that PEVs and PHEVs could provide some or perhaps most of the benefits that utility-related storage provides. Specifically, it may be cost-effective to charge electric vehicles when demand and energy prices are low or relatively low and then to dispatch aggregated power from those vehicles (using stored energy and/or the hybrid’s fuel-driven power plant) to support the grid, especially during grid emergencies.

On the positive side, the proliferation of PEVs and PHEVs could lead to economies of scale and lower prices for advanced batteries and battery systems, including system management and grid integration (interconnection, control, and communications).

7.4.8. Increasing Use of Intermittent Renewables

Storage seems poised to be important as a complement to the expected increase of intermittent renewables. If nothing else, some output from intermittent renewables occurs when energy is not valuable and/or can change rapidly, making grid operations challenging and reducing the renewables’ capacity credit. Three key facets of renewables-storage value propositions are notable: 1) capacity firming, 2) energy time-shift, and 3) grid integration.

7.4.9. Increasing Use of Modular Distributed Energy Resources

An emerging theme in the electricity marketplace is the use of modular electricity resources that are located near loads and downstream from overloaded T&D facilities. Distributed energy resources (DER) include generation, storage, and geographically-targeted load management and conservation.

On important reason for the increased interest in DER is that resources located near loads can provide more benefits than more remote resources. Other key drivers of interest in modular distributed resources include increasing congestion of regional transmission systems; challenges associated with paying for and siting large generation and transmission infrastructure; improvements in DER technologies; Smart Grid, and proliferating of rooftop/distributed photovoltaics.

7.4.10. Reducing Generation Fuel Use and Air Emissions

It is important to consider the fuel-use-related and air-emissions-related implications of storage because of trends toward reducing resource extraction, transportation and use, and policies that emphasize reducing air emissions due to generation. Depending on the circumstances, storage may be an important element of an overall strategy to reduce generation-related fuel use and air emissions.

As summarized in Section 5.3.7 and Section 5.3.8, storage can lead to reduced fuel use and air emissions in at least three ways: 1) time-shift energy from relatively efficient and/or clean baseload generation (*e.g.,* combined cycle, geothermal or wind generation) to offset use of less efficient, dirtier on-peak generation (*e.g.,* older, simple cycle combustion turbines), 2) reduce I^2R energy losses if energy is transmitted during off-peak times, and 3) dynamic operating benefits.

7.4.11. Storage Technology Innovation

Innovation by storage technology and storage system developers is accelerating, especially regarding batteries and, to a lesser extent, capacitors and CAES. Key drivers seem to be transportation-related uses, the expected increased use of intermittent renewables and a growing need for operational flexibility for the electricity grid.

8. Conclusions, Observations, and Next Steps

8.1. Summary Conclusions and Observations

8.1.1. The Storage Opportunity

Electric energy storage is poised to become an important element of the electricity grid and marketplace of the future. Storage has unique features and characteristics that make it useful for significant existing and emerging electric-utility-related opportunities and challenges.

Notable opportunities and challenges that storage can address include, but are not limited to, the following (presented in no particular order):

- Storage offsets the need for *additional* peaking generation capacity.
- Storage enables more optimal operation of the *existing* generation fleet, thereby reducing generation ramping and part load operation which, in turn, reduces equipment wear, fuel use, and air emissions.
- Storage is well-positioned to enable effective, optimal integration of intermittent renewables and possibly baseload renewables.
- Storage is well-suited to provide ancillary services, especially load following, area regulation, and electric supply reserve capacity. Distributed storage would be especially valuable for voltage support.
- Properly located storage can reduce congestion of existing transmission, reduce the need for additional transmission capacity, and defer the need for expensive subtransmission and distribution upgrades. Similarly, storage use can increase utilization of existing T&D assets, and in some cases it could be used to extend the life of existing T&D equipment – especially aging underground cables.
- Distributed storage will probably become a crucial element of the Smart Grid, and it can facilitate/enable increasingly important 'demand response' resources.
- Modular storage provides utility planners and engineers with flexible, reliable, and possibly less-risky alternatives to investments in conventional, inflexible, 'lumpy' T&D capacity additions.
- Distributed storage is well-suited to addressing growing electric service power quality and electric service reliability challenges, possibly by enabling utilities to provide differentiated electric service with higher quality and/or reliability (for a premium price).
- Utility customer-owned storage can be used to manage increasing electricity-related costs by time-shifting low-priced energy and by using storage to provide grid 'services', probably in conjunction with electric resources aggregators.

8.1.2. Storage Opportunity Drivers

Several current and emerging storage opportunity drivers have been recognized. The following are especially notable (presented in no particular order):

- Increasing recognition by lawmakers, regulators, and policymakers of the important role that storage should play in the electricity marketplace of the future.
- Increasing sophistication and savvy of load and distributed resource aggregators.
- Increasingly rich electricity price signals (*i.e.*, for energy, capacity, and ancillary services).
- Tax and regulatory incentives for storage.
- Expected proliferation of plug-in electric vehicles and plug-in hybrid electric vehicles.
- Increasing use of modular distributed energy resources for on-peak electric supply, ancillary services, and transmission congestion relief.
- Increasing use of intermittent renewables.
- Growing need for improved electric service power quality and reliability.
- Storage technology innovation, including improved subsystems (especially power conditioning) and storage system integration; battery innovation will accelerate, perhaps dramatically, due to development related to electric vehicles.
- An increasingly ‘smart’ electricity grid will enable effective integration of some renewables and integration and dispatch of distributed resources, including demand response, generation, and storage.

8.1.3. Notable Stakeholders

The storage opportunity involves numerous stakeholders. Understanding stakeholder interests and relationships is crucial for several reasons. Perhaps the most important reason is that not all benefits accrue to the same stakeholder. In fact, some benefits may involve conflicting interests. Consider a utility customer that uses storage to reduce its electricity-related costs. To the utility, the resulting ‘revenue loss’ increases the average price that customers at large must pay (because the utility receives less revenue without a commensurate reduction of fixed cost.)

Also, the existence of numerous stakeholders is important in that storage value propositions and storage projects may require a significant amount of coordination and cooperation among diverse stakeholders, possibly with conflicting interests.

Below are eight notable ‘beneficiary stakeholders’ (*i.e.,* parties that derive benefit from storage):

- Specific electricity end users who use storage to reduce electricity cost
- Utility ratepayers at large
- Utilities
- ‘Merchant’ storage project owners (entities that use storage for profit only)
- Aggregators

- Storage equipment and services providers
- Society at large (*e.g.*, for improved environmental quality and economy)

Several 'institutional stakeholders' or 'gatekeeper stakeholders' are also notable:

- Legislators and policymakers
- Utility engineers and capacity planners
- Engineering standards organizations
- Federal and state energy/utility regulatory agencies
- Regional independent system operators
- Local safety, siting, planning and land use agencies
- 'Host' communities

8.1.4. Notable Challenges

The storage opportunity involves some important challenges. It is prudent to be familiar with those challenges when evaluating prospects for storage in general, and for specific storage-related applications/benefits, value propositions, projects, locations, and regions/jurisdictions.

Several notable challenges include the following (in no particular order):

- Storage's relatively high cost per kW installed, compared to the benefit associated with most *technically* viable value propositions
- Lack of storage-related regulatory rules and 'permission,' especially regarding distributed storage
- Prevailing electric energy and services pricing that are not economically efficient (though, this is changing)
- Limited risk/reward sharing mechanisms (especially between utilities and customers and/or aggregators)
- Permitting and siting rules and regulations are not well-established for storage
- Limited familiarity with, knowledge about, and experience with storage
- Limited storage-related engineering standards and evaluation methodologies and tools
- Investor-owned utilities' 'rate-based' (or revenue requirement) financials that lead to a strong preference for investments in equipment and aversion to expense-based alternatives
- Storage must compete with many technologies, concepts, and programs (*e.g.*, demand response, Smart Grid, distributed generation, and renewables) for its place in the electricity marketplace of the future
- Coordinating among numerous stakeholders for 'permission' to use grid-connected storage and./or to aggregate benefits

See Appendix G for a more detailed list of challenges.

8.1.5. The Importance of Benefits Aggregation

The most important topic addressed in this guide is the aggregation of benefits into attractive value propositions (*i.e.*, a value proposition for which the total benefit exceeds the total cost by an amount that yields an acceptable-or-better return on investment). That theme is so important because in many situations two or more benefits will be required so the total benefit exceeds the total cost.

The primary purpose for this guide is to provide analysts with a framework for evaluating storage prospects for specific value propositions, including guidance about identifying and ascribing value to specific benefits that serve as building blocks for value propositions. Ideally, this framework will provide the foundation, and possibly the mindset, needed to recognize and characterize attractive value propositions.

As an aside: Given the emphasis on *benefits*, an important theme in this report is the need to maintain a crisp distinction between storage *applications* and the *benefits* that accrue if storage is used for a given application. (Applications are ways that storage is *used*, whereas benefits are primarily *financial*, including increased revenue and/or reduced or avoided cost.)

8.1.6. Multi-faceted Nature of the Storage Opportunity

Given the foregoing, clearly the storage opportunity is multi-faceted. A robust understanding of the storage opportunity requires at least some familiarity with several of those facets. Consider just a few:

- Many possible application/benefit combinations
- Numerous beneficiary stakeholders and institutional/gatekeeper stakeholders, some with conflicting interests
- Myriad rules, regulations, and permitting requirements
- Applicable market rules, tariffs, and pricing significantly affect the attractiveness of storage in specific regions and locations
- Role of storage relative to the electric supply generation fleet, renewables, demand response, Smart Grid, PEVs, and PHEVs
- Most existing storage technologies continue to improve, and advances involving emerging storage technologies are accelerating

8.2. Next Steps – Research Needs and Opportunities

Although utility-related storage opportunities are receiving increasing emphasis, more extensive research, development, and demonstration are needed. The elements of a robust storage-related research and development agenda are briefly characterized in this section.

8.2.1. Establish Consensus about Priorities and Actions

A key challenge for storage is the combination of diverse benefits and diverse stakeholders. Although that situation seems likely to persist, an important next step is to work toward a common understanding among stakeholders about several key topics, including the following: a) existence and magnitude of benefits; b) important value propositions, including the societal value proposition; c) key challenges and solutions; d) standards and rules needed (interconnection, permitting, *etc.*); e) market potential; f) the role of storage relative to and/or in conjunction with Smart Grid and demand response programs; g) storage technology and system cost and performance criteria, including definitions and values; and h) storage technology and value proposition demonstrations.

8.2.2. Identify and Characterize Attractive Value Propositions

This guide emphasizes the concept of value propositions and includes a few examples of possibly attractive value propositions. A helpful next step would be to establish a menu of model/generic value propositions that are a) generally accepted/recognized, b) financially attractive, and c) technically viable. Furthermore, value propositions targeted should be those involving somewhat-to-very significant market potential. Those value propositions would be used by storage advocates, project developers, technology and systems developers, regulators, policymakers, researchers, and prospective end users to focus their respective efforts.

8.2.3. Identify and Characterize Important Challenges and Possible Solutions

A crucial initial step towards consensus-building is to identify the most important challenges that could significantly delay and/or limit deployment of storage. First, the challenges should be characterized and then prioritized. Possible criteria to use in establishing priorities could include 1) potential showstoppers, especially those that are most likely to occur; 2) challenges whose solutions require a long lead time; 3) challenges that affect early adopters and/or users which could purchase significant amounts of storage in the near term; and 4) challenges that are most likely to create or to reinforce unhelpful misperceptions. After priorities are established, the next step would be to identify and develop an approach to address those challenges.

8.2.4. Identify, Characterize and Develop Financial and Engineering Standards, Models, and Tools

If storage is to reach its potential, one key priority is to identify, characterize, and develop the engineering and financial/accounting standards needed to evaluate important technical and financial criteria. Once those standards are established, analysts will need models and tools to apply them. Presently, those standards, tools, and models are largely undeveloped and/or they require adaptation and evolution of existing tools.

8.2.5. Ensure Robust Integration of Distributed/Modular Storage with Smart Grid and Demand Response Programs

Smart Grid and demand response programs are poised to be important elements and enablers of the modern electricity grid and the electricity marketplace of the future. It seems likely that storage will be an important part of Smart Grid and demand response programs.

It is important to ensure robust and appropriate consideration of storage's roles and benefits as Smart Grid infrastructure and demand response, protocols, functionality, hardware, communications, and controls are developed, and as the Smart Grid and demand response programs are deployed.

8.2.6. Develop More Refined Market Potential Estimates

While the transparent, auditable, simplistic, maximum market potential estimates provided in this guide may provide a helpful point of departure, more robust methods are needed to refine those estimates. Such estimates are important metrics for politicians, policymakers, regulators, storage advocates, potential storage users, and storage vendors as they seek to gauge the potential implications and attractiveness of storage.

8.2.7. Develop Model Risk and Reward Sharing Mechanisms

As mentioned elsewhere in this guide, important discontinuities between some key stakeholders' interests – especially between utilities and customers – make risk and reward sharing difficult or impossible. Nevertheless, many otherwise attractive value propositions are not possible without risk and reward sharing, especially value propositions involving locational benefits and distributed/modular storage.

Perhaps the best example is the benefit for T&D upgrade deferral or T&D equipment life extension. Consider the example of a T&D upgrade deferral or life extension that would reduce the utility's total cost-of-service (an avoided cost) by $100,000 for one year.

Ideally, the utility would have the flexibility to share the avoided cost with customers that are willing and able reduce load, when needed, to enable the deferral. When called upon to reduce load, those customers could turn off loads (demand response) and/or use on-site generation and/or on-site storage. Peak load reduction could also be accomplished using energy efficiency.

Unfortunately, most utilities do not have the regulatory 'permission' or the transactional framework for such risk and reward sharing. If nothing else, the utility should be allowed to concentrate conventional demand response and energy efficiency incentives toward the part of the grid where T&D upgrade deferral or life extension is needed.

8.2.8. Develop Model Rules for Utility Ownership of Distributed/Modular Storage

For a variety of reasons, most utilities do not have regulatory permission to use storage *in lieu* of T&D equipment. One of the more important near terms objectives for the storage community is to advocate for utility permission to own and operate distributed/modular storage, just like any other equipment. Model rules for such utility ownership could spur the development of formalized rules at the state level.

8.2.9. Characterize, Understand, and Communicate the Societal Value Proposition for Storage

It is important to characterize, understand, and communicate the societal value proposition for storage (as described in Section 6.7) for at least two key reasons. First, society at large has a significant stake in the storage opportunity because some of the key benefits accrue, in part or in whole, to society at large (*e.g.*, reduced air emissions and reduced land use impacts from reduced need for new infrastructure). Second, some significant storage benefits may accrue to more than one stakeholder, including utility ratepayers as a group and/or to society as a whole, making 'stakeholder integration' and risk and reward sharing mechanisms especially important for societal benefits.

8.2.10. Storage Technology and Value Proposition Demonstrations

New storage technologies, subsystems, and storage system configurations must establish a record and reputation as a reliable, cost effective alternative before wide-scale acceptance. That same challenge applies to undemonstrated storage benefits and value propositions.

Establishing a track record and reputation often requires several demonstrations. Therefore, numerous demonstrations may be necessary (especially for modular/distributed storage) before wide-scale deployment of additional storage will occur.

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Appendix A – Ancillary Services Overview

In broad terms, ancillary services are necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission (FERC), they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Introduction

The two primary functions of the electricity grid are 1) providing a supply of electric energy, primarily using generation that converts fuel to electricity in real-time and 2) delivering that energy to customers via the transmission and distribution (T&D) system. In addition to resources that provide the electric energy; additional resources – collectively known as ancillary services – support the overall operation of the grid. Ancillary services are defined by FERC as those services necessary to support the delivery of electricity from seller to purchaser while maintaining the integrity and reliability of the interconnected transmission system (‘the network’). The specific definitions used by FERC for various ancillary services are listed in Table A-1.

To one extent or another, energy storage can provide many of those ancillary services. Storage used to provide some of the ancillary services may also be used for other applications, including power quality, reliability, and others.

Regulation *versus* Load Following

Two ancillary services – regulation and load following – are somewhat similar; however, to understand implications for storage value propositions, it is important to distinguish between them:

> Together, regulation and load following address the temporal variations in load (and generation that does not accurately follow control signals). The key distinction between load following and regulation is the time period over which these fluctuations occur. Regulation responds to rapid load fluctuations (on the order of one minute) and load following responds to slower changes (on the order of five to thirty minutes). Load following is defined as the 30-minute rolling average of system load; regulation is then the difference between actual load for each 30-second interval and the rolling average. Hourly load following is defined as the difference between the highest and lowest values of the rolling average within the hour. Regulation is defined as the standard deviation of the 120 regulation values for the hour. Finally, the implications of the current block-scheduling conventions on load following and regulation are discussed, as is the need for a new scheduling convention.[A1]

Table A-1. Ancillary Services and Their Common Definitions

System Control	Scheduling generation and transactions ahead of time, and controlling some generation in real time to maintain generation/load balance.
Reactive Supply & Voltage Control	The generation or absorption of reactive power from generators to maintain transmission system voltages within required ranges.
Regulation	Minute-by-minute generation/load balance within a control area to meet NERC standards.
Spinning Reserve	Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency-responsive' spinning reserve responds within 10 seconds to maintain system frequency.
Supplemental Reserve	Generation capacity that may be offline or curtailable load that can respond within 10 minutes to compensate for generation or transmission outages.
Energy Imbalance	Correcting for mismatches between actual and scheduled transactions on an hourly basis.
Load Following	Meeting hour-to-hour and daily load variations.
Backup Supply	Generation available within an hour for backing up reserves or for commercial transactions.
Real Power Loss Replacement	Generation that compensates for losses in the T&D system.
Dynamic Scheduling	Real-time control to electronically transfer either a generator's output or a customer's load from one control area to another.
Black Start	Ability to energize part of a grid without outside assistance after a blackout occurs.
Network Stability	Real-time response to system disturbances to maintain system stability or security.

Please see Appendix D for more about storage for Load Following and Appendix E for more about storage for Area Regulation.

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Appendix B – Storage Replacement Cost Estimation Worksheet

The worksheet shown below is an example of a simple methodology that can be used to estimate the cost incurred during battery operation due to battery wear (*i.e.*, damage). It spreads the damage-related cost across each unit of energy discharged to establish a value that represents the cost for battery replacement that is incurred per unit of energy output from the battery.

Life	10		
Annual Capacity Factor	0.07	Annual Operation Hours	613
Discount Rate	10.0%		
Annual Use Cycles	250	Operation Hours Per Use Cycle	2.45
Standard Refurbishment			
Use Cycles Per Refurbishment	1,000	Years per Replacement	4.00
		Replacement Frequency	1.50
Refurbishment Cost ($/kWh $Year 1)	300	Total Refurbishment Cost ($/kW, $Year 1)	450
Refurbishment Cost Escalation	2.5%	Annual Refurbishment Charge ($/kW, $Year 1)	45

	$Year 1	$Current	$PW
Refurbishment Cost ($/kW)	450	504	321
(¢/kWh)	7.3	8.2	5.2

Caveats

1. Treats refurbishment like an expense, not investment...

2. ...but does not include tax deduction for the expense.

3. Includes fractional refurbishments if "Replacement Frequency" is not an integer.

4. This is a somewhat simplistic treatment of refurbishment cost annualization. It allocates all refurbishment costs (in the form of the annual average) across all years although it could be allocated in the years before/until the last refurbishment; though annual allocations in those years would be higher. Also, the cost escalation is applied to the annual average each year. It could be allocated only in years when allocation occurs.

		Year =>																			
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Refurbishment Annual Cost ($/kW, $Year 1)	450	45	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0	0
($Current)	504	45	46	47	48	50	51	52	53	55	56	0	0	0	0	0	0	0	0	0	0
($PW)	321	45	42	38	35	33	30	28	26	24	22	0	0	0	0	0	0	0	0	0	0
Refurbishment Unit Cost (¢/kWh)	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
($PW)	5.2	7.3	6.8	6.2	5.8	5.3	4.9	4.5	4.2	3.8	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Appendix C – Distributed Energy Storage for Voltage Support and Reactive Power

Introduction to Reactance in AC Circuits

An important technical challenge for electric grid operators is managing the effects from a phenomenon called *reactance* in an alternating current (AC) electrical circuit.* Reactance is caused by elements within an AC circuit (*i.e.,* inductors and capacitors). The effects from reactance are related to an accumulation of electric or magnetic fields in the circuit elements when current is flowing. The electric and magnetic fields, in turn, produce an opposing electromotive force that is proportional to either the rate of change (time derivative) or accumulation (time integral) of the current.

Perhaps the most important manifestation of reactance in an AC circuit is that capacitors and inductors cause voltage and current to be 'out of phase' (*i.e.,* to not be synchronized). Specifically, rather than the ideal situation involving voltage and current which are synchronized, capacitors cause current to *lead* the voltage and inductors cause current to *lag* the voltage. Figure C-1 provides a graphical representation of the phenomenon.

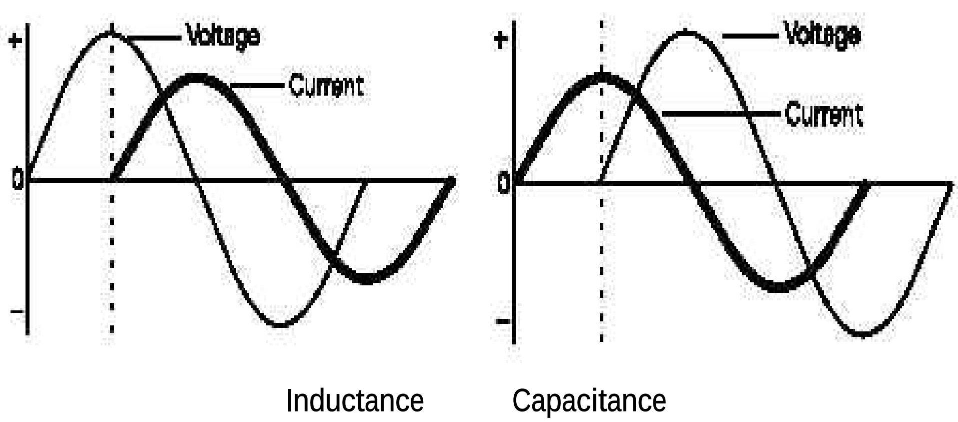


Figure C-1. Leading and lagging current due to inductance and capacitance (reactance) in an AC circuit.

In the left graph of Figure C-1, the two plots of voltage and current show capacitive reactance (current leads voltage). The two plots in the graph on the right show effects from inductive reactance (current lags voltage). The degree to which current leads or lags depends on the alternating current circuit's operating frequency (*e.g.,* electric grids operate at 50 or 60 Hz) and the capacitance and inductance in the circuit.

* AC power involves current flow (and voltage) that varies between a positive and a negative level. Electricity power systems use AC power that oscillates between negative and positive values 60 times per second (i.e., 60 Hertz AC). Among other advantages, AC power enables transmission over longer distances than systems using direct current (DC) power (power that has a constant current and a constant voltage).

Importantly, to the extent that current leads or lags voltage, the effective voltage is reduced, in turn reducing the amount of usable power that can be delivered (*i.e.*, reactance reduces the effective load carrying capacity of the grid). Note that, normally, reactance in the electricity grid is dominated by reactance from *inductive* loads (causing current to lag the voltage), especially motors.

Power Factor

The power factor of an AC electric system is defined as the ratio of *real power* to *apparent power*.

Real power (also known as 'true power') can be defined as the amount of usable power that can be delivered to loads in an AC circuit. More specifically, real power indicates the amount of work that can be accomplished over a given amount of time based on the rate at which the circuit can deliver electric energy. Real power could also be thought of as the 'effective' power or the useable power. The most common units used to express real power are watts (W) or kilowatts (kW).

Apparent power is simply the product of the voltage and current within a circuit, irrespective of whether voltage and current are synchronized and how much work can be accomplished using the electric energy that the circuit can deliver to loads. The most common unit of apparent power is volt-Ampere (volt-Amp). Note that most power equipment – such as power supplies, wires and transformers – are rated based on their apparent power (volt-Amps).

In any given circuit, the apparent power can be somewhat or significantly greater than the real power because 1) during each alternating current cycle, energy is stored within loads and then returned to the circuit; and/or 2) 'non-linear' loads distort the current's (sine) wave form within the circuit. Common non-linear loads include most electronic equipment, which have non-linear power supplies, and electronic ballasts used for lighting.

Of particular interest are effects from reactive loads that lead to the presence of reactive power in the circuit. Units of reactive power are volt-Amps reactive (VAR). VAR reduces real power because the associated reactance changes the temporal relationship between voltage and current in the AC circuit as described above. (Note that apparent power is the combination of real power and reactive power.)

The concept of power factor is important in part because – to the extent that the real (useable) power is less than apparent power – the amount of power that can be delivered to loads by a circuit with power factor that is less than one (unity) circuit is reduced. Consider the example of a circuit rated to deliver 10 MVA (apparent power) with a power factor of 0.9. That circuit could serve

$$0.9 \times 10 \text{ MVA} = 9 \text{ MW of load.}$$

One implication is that a larger circuit (capacity) is needed to deliver a given amount of useful energy. Because more current flows within the circuit (for a given amount of energy delivered), there are more I^2R energy losses within the circuit.

(For more detail about true, reactive, and apparent power, readers could refer to the *All About Circuits* website: http://www.allaboutcircuits.com/.)

Utility Responses, Overview

Utilities use two important means to compensate for the presence of reactance (*i.e.*, to restore voltage to and/or to maintain voltage at the desired level). Generic terms for managing effects from VAR are ‘VAR support’ and ‘VAR compensation’.

One such technique – involving an ancillary service known as ‘voltage support’ – is to produce reactive power (power that has lagging or leading current). The reactive power is meant to cancel out the effects of reactance in the power system.

Another more localized approach – called ‘power factor correction’ – involves using equipment within the T&D system to offset effects from localized reactance. In most cases, power factor correction involves use of power factor correcting capacitors that offset effects from localized inductance.

Distributed Storage for Voltage Support

The balance of this appendix is section is based largely on the research of scientists at Oak Ridge National Laboratory (ORNL). Their objective was to evaluate the potential for distributed generation as a resource for VAR compensation. In most cases, storage systems can or could be designed to provide the same service. The ORNL work tested the hypothesis that “[distributed generation] can play a larger and more significant role than at present in relieving voltage stability problems due to both a) suboptimal dispatch of reactive power supplies and b) reactive power supply shortages.”[C1]

Reactive power for voltage compensation is compelling for several reasons. Among the reasons given by authors of the ORNL report, “past power blackouts have been attributed to problems with reactive power transport to load centers.”[C2] Although reactive power for voltage compensation is a relatively small *portion* of total cost to generate and transmit electricity, it does account for billions of dollars in *total* cost. Another compelling reason is that most central generation technologies, especially newer ones, are not well-suited to reactive power generation because generation is usually optimized for real (*i.e.*, true) power generation at a constant output.

Importantly, unlike real power, reactive power cannot be transmitted over long distances. Consequently, central generation may not be the best source of reactive power. Conversely, a growing array of smaller, modular power technologies (*e.g.*, any type of power system with an inverter that has VAR support capability, distributed generation, energy storage, and possibly even demand response) could provide other sources of VAR support, and provide such support closer to the loads that pose the biggest challenges.

Voltage Support using Reactive Power

In simple terms, voltage control for an AC power system is accomplished primarily by managing reactive power. This is done by injecting and/or absorbing reactive power, when needed, as close as possible to the location where reactance is a problem. The amount of reactive power needed normally varies as a function of the transmission line loading. Heavily loaded lines require more reactive power than lightly loaded lines. As reactive power needs in the transmission system vary, the Independent System Operator (ISO) and regional transmission organizations (RTOs) adjust the supply of reactive power.

The Federal Energy Regulatory Commission (FERC) separates voltage control into two categories: generation-based and transmission-based.

Generation-based voltage control is an ancillary service, and transmission-based voltage control is included as an element of transmission service agreements or tariffs. Generation-based VAR support is needed to operate regional power systems and electricity markets. (Other common ancillary services include spinning reserve, contingency, emergency, or supplemental reserve, and regulation.) According to authors of the ORNL report, "It is variously estimated that providing this bundle of ancillary services costs the equivalent of 10-20% of the delivered cost of electric energy."[C3][C4]

The process of managing reactive power in transmission systems is well understood technically. The three primary objectives of reactive power management are as follows: 1) maintain adequate voltages throughout the transmission system under normal and contingency conditions, 2) minimize congestion that affects flow of real power, and 3) minimize real-power losses.

Voltage control is usually centralized because coordinated control is needed among the various entities and equipment in the electric grid to ensure effective operation of the system (*i.e.,* to keep voltage levels within necessary parameters). System operators and planners use sophisticated computer models to design and operate the power system reliably and economically. These functions are not readily distributed to individual sub-regions or to separate market participants.

An important responsibility of power system planners is to address what is generically called 'grid security'. It involves planning whose goal is to ensure adequate operation of the power system (generation and transmission) during a range of conditions and contingencies. It involves, in part, modeling the electric grid system under a broad range of conditions to ensure that the electric grid has adequate reserves when transmission lines or generators fail, as well as during peak demand periods. (Normally, power systems maintain sufficient reserves to serve load should a major generation plant or transmission line fail, commonly called an N-1 contingency).

Reactive power resource technologies differ significantly with respect to the amount of reactive power that can be produced under given conditions, response speed, and capital cost. Reactive power sources can be categorized as either *static* or *dynamic*.

Common static reactive power sources include transmission and distribution (T&D) equipment such as substation capacitors. Notably, these T&D-based options are considered to be part of the utility's capital investment portfolio (of infrastructure equipment). The equipment cost is added to the utility 'revenue requirement' – the amount of revenue required, from users, to cover all costs.

Dynamic reactive power sources include generation facilities, which are capable of producing both real *and* reactive power, and synchronous condensers, which produce *only* reactive power. Generation equipment may be owned either by utilities or independent entities. Often, reactive power is bought and sold so that the cost is covered by market-based or market-like prices.

Providing Reactive Power Locally

A key difference between VAR support (or reactive power supply) and other ancillary services is that reactive power cannot be transmitted over long distances. Reactive power needs occur in direct proportion to the distribution of load across a system and the proximity between generators and load centers.

Reactive power from distributed energy resources (DER), including distributed generation and distributed energy storage, could provide distributed dynamic voltage control in response to variations of reactive power needs within distribution systems. To serve as a reactive power resource, the DER must be able to inject and absorb reactive power. Conversely, distributed generation and distributed energy storage that do not have the ability to generate or absorb reactive power can *degrade* voltage. Notably, many DER are connected to loads and/or to the grid via equipment that incorporates solid-state power electronics that may be designed to provide reactive power compensation.

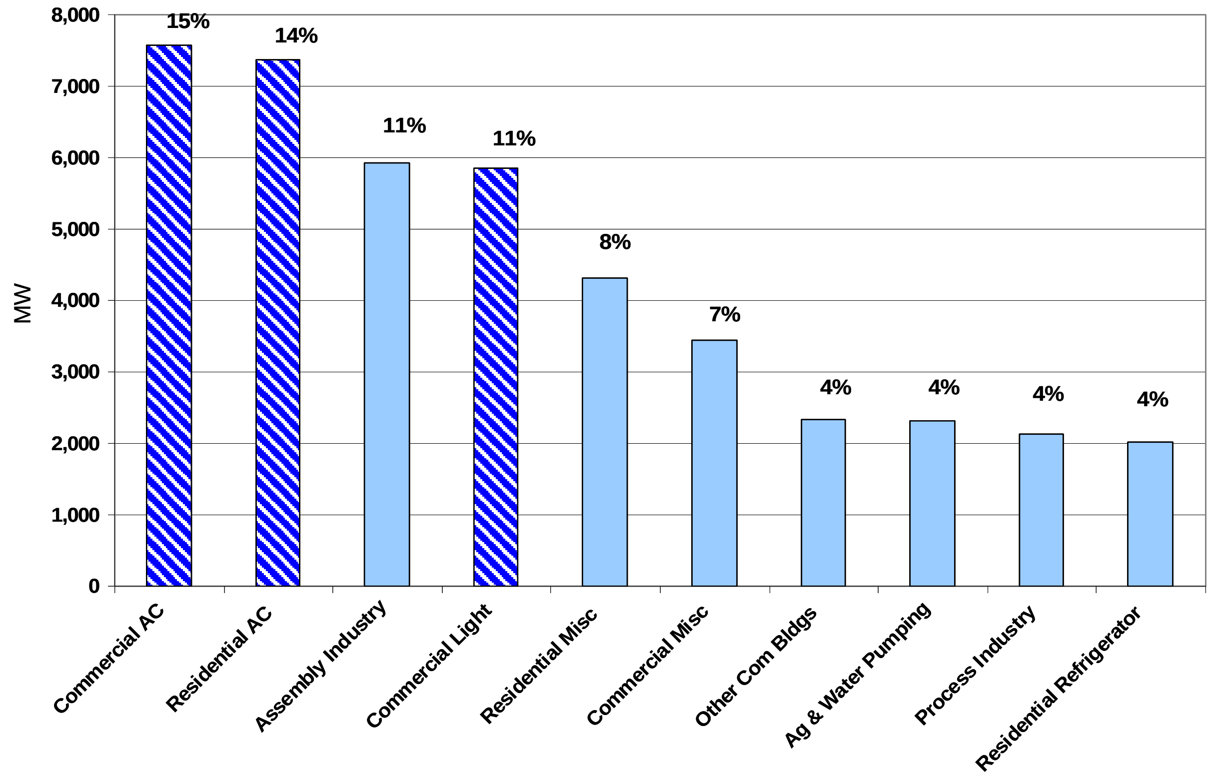
The implications and possibilities for reactive power compensation using DER capacity are not well understood. Nevertheless, reactive power is currently provided, in part, by what could be called modular/distributed sources (*e.g.,* static VAR compensators and capacitor banks). So, intuitively, it seems likely that there are exploitable synergies between the localized need for reactive power (usually near loads) and increasing emphasis on DER. Perhaps more importantly, aggregated DER capacity (if dispatched in a coordinated way) could be part of a robust approach to region-wide grid stability during major power interruptions involving declining area-wide or system-wide voltage.

As previously noted, reactive power needed to stabilize voltage cannot be transmitted very far. So, in general, *local* sources of VAR support are most helpful, especially if interruptions involve transmission corridors. Additionally, many DER types can respond rapidly to reduce the chances of a total loss of power.

Storage may be best suited to this application if rapid response is important. Some storage types reach their full discharge rate within seconds to just a few milliseconds, these include capacitors, flywheels, and superconducting magnetic energy storage. (Note that, although conventional capacitors are good for managing reactance under normal operating conditions, they do not perform well as a voltage support resource because they draw more current as voltage drops, possibly adding to cascading overloads.) In contrast, most types of generation take a few to many minutes to respond fully (*e.g.,* pumped hydroelectric and compressed air energy storage).

Aggregated modular storage deployed at or near loads, for reasons other than voltage support, could provide very helpful voltage support when and where needed. Finally, by picking up or turning off specific types of load when grid anomalies occur, DER can reduce voltage degradation, thereby reducing the possibility of cascading outages.

The most challenging loads during such an event include small motors, especially those used in smaller air conditioning equipment to operate the compressor. Figure C-2 shows that, in California, such loads account for a significant portion of peak demand. Those motors pose such a significant challenge because as grid voltage drops during local or region-wide grid emergencies, the motors draw more current to maintain power which exacerbates the voltage problem. The same motors can also pose a relatively significant challenge as the grid is re-energized after outages.



Source: California Energy Commission.[C5]

Figure C-2. Peak demand (in MW) by end use in California.

References

[C1] Li, F. Fran. Kueck, John. Rizy, Tom. King, Tom. *Evaluation of Distributed Energy Resources for Reactive Power Supply, First Quarterly Report for Fiscal Year 2006*. Prepared for the U.S. Department of Energy by Oak Ridge National Laboratory and Energetics Incorporated. November 2005.

[C2] *ibid*. [C1].

[C3] *ibid*. [C1].

[C4] Kirby, Brendan. Hirst, Eric. *Ancillary Service Details: Voltage Control*. Oak Ridge National Laboratory, Energy Division. Sponsored by The National Regulatory Research Institute. Oak Ridge National Laboratory Report #ORNL/CON-453. December 1997.

[C5] *California's Electricity Situation: Summer 2005*. Presentation prepared by the staff of the California Energy Commission, California Public Utilities Commission, and California Independent System Operator. February 22, 2005

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Appendix D – Storage for Load Following

Storage can provide load following *up* by increasing the rate of discharge and/or decreasing the rate of charging, as described below.

Consider the example depicted in Figure D-1 which shows how charged storage with one hour of discharge duration can provide two hours of load following up by *discharging*.

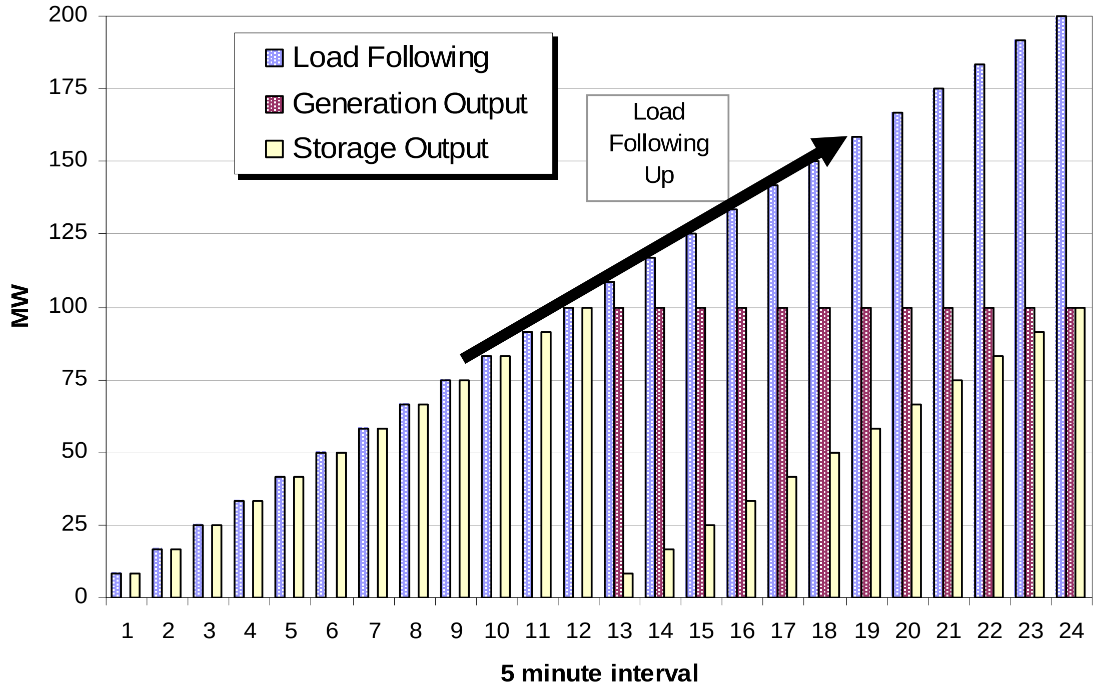

Figure D-1. Two hours of load following up with one hour of storage discharge.

In Figure D-1, the time-specific aggregated load following capacity needed is indicated by the blue bars labeled Load Following. The rate of storage *discharge* increases as load increases (shown by the yellow bars labeled Storage Output). After the first hour of load following with storage, a full 100-MW block of generation is dispatched (shown by the red bars) while storage discharge is curtailed (at interval #13). Throughout the second hour of load following, the storage output is increased every five minutes (as it was during the first hour) as load increases. At the beginning of the next hour (not shown), another 100-MW block of generation is dispatched and storage output is halted.

Storage *charging* can also be used to provide load following up by reducing the rate of charging throughout an hour, commensurate with increasing load. Consider the example shown inFigure D-2. At the beginning of the first hour of load following, a 100-MW generator is dispatched to full output (see the red bars labeled Generation Output). At the same time, storage begins charging at a rate equal to the 100-MW rating of the generator that was just dispatched. Every five minutes, the rate of storage charging is reduced to the extent that load has increased (note the yellow bars labeled Storage Charging). The resulting load following up is shown by the blue bars. At the beginning of the second hour of load following, the second 100 MW of generation is dispatched (at full output), and storage charging commences again at a rate (100 MW) equal to the output of the second generator. Finally, at the beginning of the next hour (not shown), more generation is dispatched (ideally, at full output) as storage operation (in this case, charging) ceases.

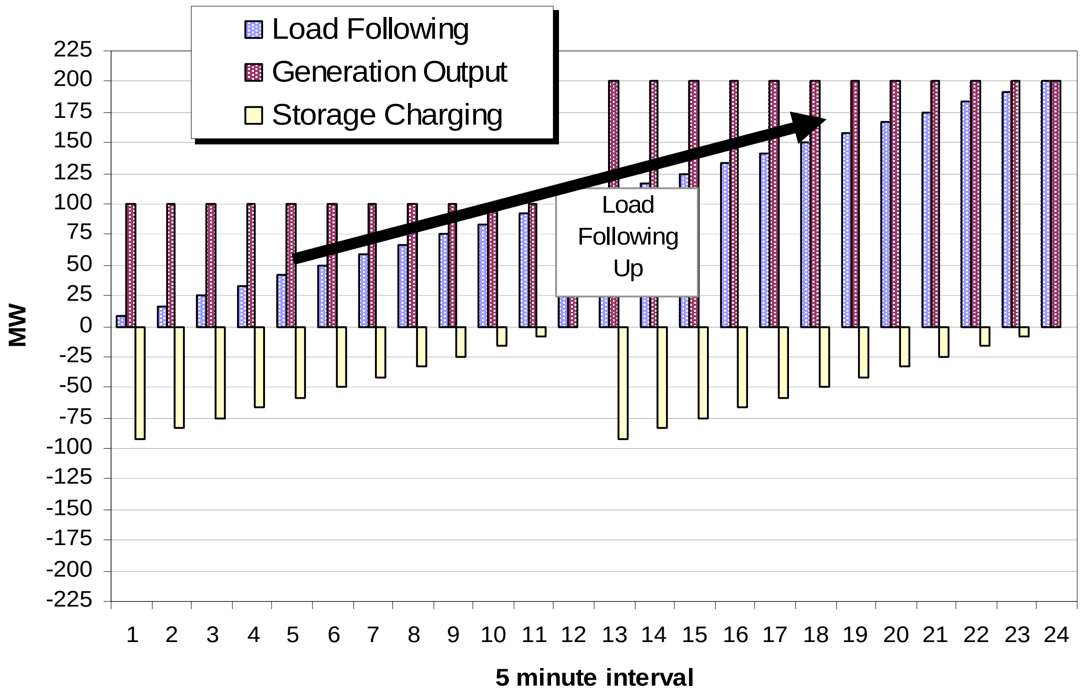

Figure D-2. Two hours of load following up with one hour of storage charging.

Storage provides load following *down* by decreasing the rate of discharge and/or by increasing the rate of charging, as described below.

For load following down involving decreasing storage discharge, the storage is cycled from full output to very low (or no) output twice in a two-hour period, providing two service hours of load following down as shown in Figure D-3. In that figure, at the end of the previous hour (not shown), a 100-MW generator is taken offline as 100 MW of storage comes online (as shown by the yellow bars labeled Storage Discharge). Another 100 MW of generation is still online (shown by the red bars labeled Generation Output). The rate of storage discharge is reduced every five minutes during the first hour as load drops. The resulting load following capacity is shown by the blue bars labeled Load Following. At the beginning of the next hour, the 100-MW generator is taken offline and the storage begins discharging again at 100 MW. Storage discharging decreases throughout the second hour as load decreases until discharging ceases at the end of the second hour.

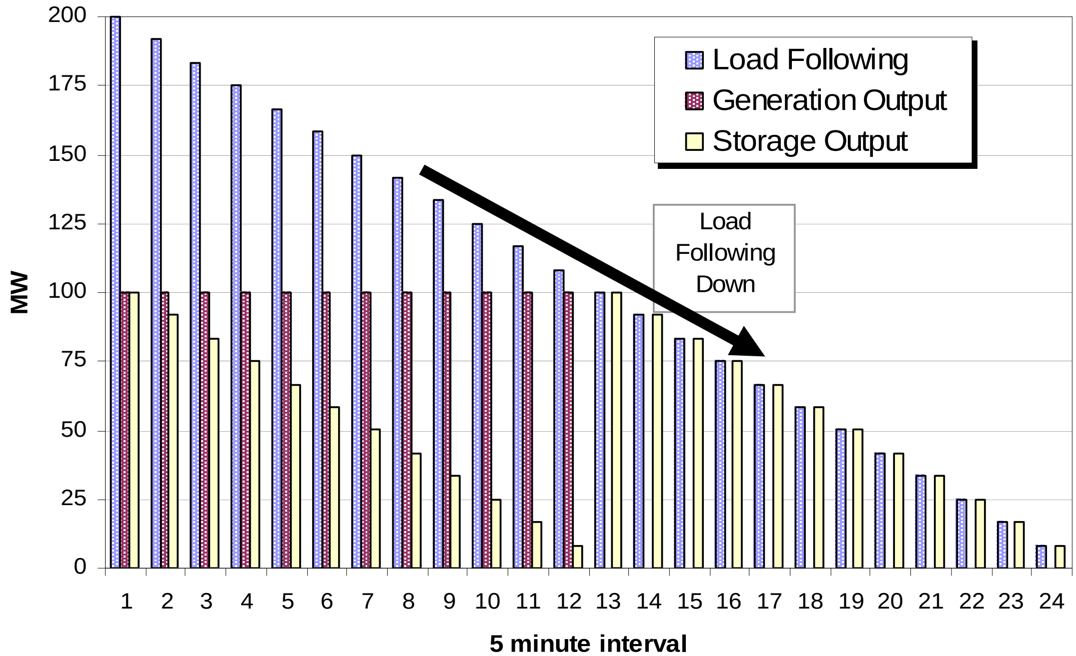

Figure D-3. Two hours of load following down with one hour of storage discharge.

Figure D-4 shows how storage can be used to provide load following down while charging. The example shown in Figure D-4 involves storage with one hour of discharge duration that is used to provide two hours of load following down.

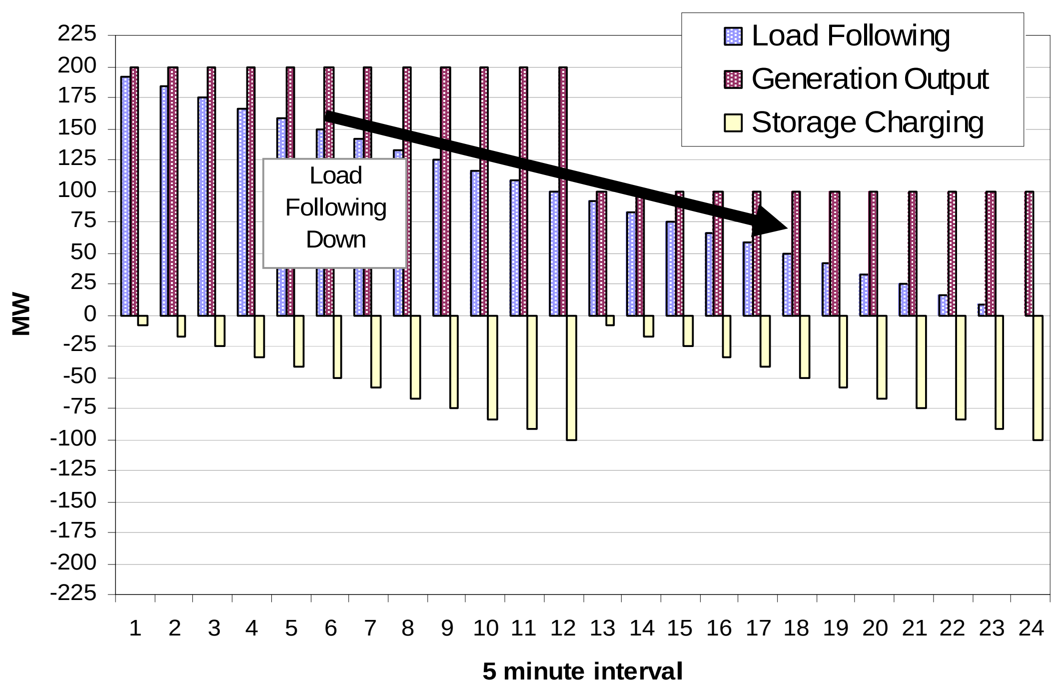

Figure D-4. Two hours of load following down with one hour of storage charging.

At the beginning of the hour, two 100-MW generators are on line for a total of 200 MW (shown by the red bars labeled Generation Output). As load decreases, there is a commensurate increase of storage charging (shown by the yellow bars labeled Storage Charging). The resulting load following capacity is shown by the blue bars labeled Load Following. At the beginning of the second hour, 100 MW of generation is taken offline, and storage charging begins again at low power. As load continues to diminish, storage charging is increased until the beginning of the next hour (not shown) when storage charging and generator operation both cease.

Energy Associated with Load Following

When using storage *charging* for load following, the energy stored must be purchased at the prevailing wholesale price. This is an important consideration – especially for storage with lower efficiency and/or if the energy used for charging is relatively expensive – because the cost of energy used to charge storage (to provide load following) may exceed the value of the load following service.

Conversely, the value of energy *discharged* from storage to provide load following is determined by the prevailing price for wholesale energy. Depending on circumstances (*i.e.*, if the price for the load following service does not include the value of the wholesale energy involved), when discharging for load following, two benefits accrue – one for the load following service and another for the energy.

Appendix E – Area Regulation

Introduction

This appendix documents a high-level analysis of the benefit from and cost for flywheel energy storage used to provide area regulation for the electricity supply and transmission system in California. The analysis is based on results from a demonstration, in California, of flywheel energy storage developed and manufactured by Beacon Power Corporation. Demonstrated was flywheel storage systems' ability to provide rapid-response regulation. (Flywheel storage output can be varied much more rapidly than the output from conventional regulation sources, making flywheels more attractive than conventional regulation resources.)

The work was sponsored by the U.S. Department of Energy (DOE) and the Sandia National Laboratories (SNL) Energy Storage Systems Program. The demonstration was supported by the California Energy Commission (CEC) Public Interest Energy Research Program. It was located at the Distributed Utility Integration Testing facility managed by Distributed Utility Associates (DUA) and located at the Pacific Gas and Electric Company (PG&E) Technological and Ecological Services research facility in San Ramon, California.

Although the specific type of storage evaluated was flywheel storage, other types of storage that can respond rapidly when conditions change can also provide the area regulation service. Those may include some types of electrochemical batteries and capacitors. And though they respond more slowly, CAES and pumped hydroelectric storage can also be used to provide area regulation.

Another desirable storage characteristic is high efficiency, because when storage *charging* occurs during regulation, any energy that is lost must be purchased at the prevailing price.

Regulation Service

Regulation is a type of ancillary service[*] that involves managing the "interchange flows with other control areas to match closely the scheduled interchange flows" and moment-to-moment variations in demand within the control area. The primary reasons for including regulation in the power system are to maintain the grid frequency and to comply with the North American Electric Reliability Council's (NERC) Control Performance Standards 1 and 2 (NERC 1999a). Regulation also assists in recovery from disturbances, as measured by compliance with NERC's Disturbance Control Standard.[E1]

When there is a momentary shortfall of electric supply capacity, the output from regulation resources is increased to provide *up* regulation when there is a momentary shortfall of power on the grid. Conversely, regulation resources' output is reduced to provide *down* regulation when there is a momentary excess of electric supply power.

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[*] Ancillary services are electric resources that are used to maintain reliable and effective operation of electric supply and transmission systems. Most often, ancillary services are provided by utilities, although an increasing portion is being provided by third parties. Six key ancillary services are 1) scheduling, system control and dispatch, 2) reactive supply and voltage control from generation sources, 3) regulation and frequency response, 4) energy imbalance, 5) spinning reserve, and 6) supplemental reserve.

Traditionally, regulation has been provided by dispatchable thermal generation facilities. They provide up regulation by increasing output when electricity demand exceeds supply, and they provide down regulation by reducing output when electricity supply exceeds demand. Generation facilities used for up regulation and those used for down regulation are operated at levels below the facilities' maximum output and above minimum output, respectively.[E2] Generation units used for regulation must be equipped with automatic generation control (AGC) equipment and be able to change output relatively quickly (MW/minute) over an agreed upon range of power output (MW).

Flywheels for Area Regulation

Flywheel electric energy storage systems (flywheel storage or flywheels) consist of a cylinder with a shaft that can spin rapidly within a robust enclosure. A magnet levitates the cylinder to limit friction-related losses and wear. The shaft is connected to a motor/generator and stator. Kinetic energy is converted to electric power via an external power conditioning unit (PCU). High-speed flywheel electricity storage is nearing commercialization. One apparently superior application of the technology is for electric power system regulation (also known as area regulation or simply regulation). Storage provides up regulation by discharging energy into the grid and down regulation by absorbing energy from the grid.

Notably, the rate of power from (or into) flywheel storage can change quite rapidly whereas output from conventional regulation sources (primarily thermal generation plants) changes slowly. Generation plants' output (up or down) changes by percentage points per minute whereas flywheels' output can change from full *output* (discharge) to full *input* (charging) and *vice versa* within a few seconds. Additionally, thermal power plants generally are most efficient when operated at a specific and constant (power) output level. Similarly, air emissions and plant wear and tear are usually lowest when thermal generation operates at constant output. Unlike thermal power plants, flywheels' performance is not affected much as output varies, and the systems are virtually emissions free.

Demonstration Plant

Results described below are for a 100-kW pilot version of a Beacon Power high-speed flywheel storage system. The pilot system consisted of seven individual flywheels, a PCU, and communication and control subsystems. It can discharge at full output for 15 minutes. The response time is described by Beacon Power to be "less than 4 seconds (at full power)." The demonstration was conducted at Distributed Utility Associates' Distributed Utility Integration Test testbed located at PG&E's Technical and Ecological Services facility in San Ramon, California. Recently, Beacon has developed a 20-MW Smart Energy Matrix™ version of the flywheel system for commercial use.

Benefits

At minimum, regulation from flywheels is at least as valuable as regulation provided by slower generation capacity. Regulation from flywheels, however, may prove even more valuable. First, flywheel storage can provide both up regulation and down regulation during the same time period (although not simultaneously). Also, because of their rapid-response (*i.e.*, their ability to change power input and output rapidly), flywheels may provide regulation that is more effective than that provided by much slower generation-based resources. Because of this advantage, regulation from flywheels is assumed to provide twice the benefit to the grid as regulation from generation.[E3][E4][E5]

Revenue for providing up and down regulation services for an entire year (8,760 hours) is estimated based on California Independent System Operator (CAISO) published hourly prices for both services for the year 2006. (See the subsection 'Price for Regulation Service' in this appendix for details.) The hourly prices are multiplied by two (to reflect the higher benefit from flywheels relative to generation-based regulation) before annual revenues are estimated.

In addition to the price for regulation in specific hours of the year, another important criterion affecting the flywheel-for-regulation value proposition is flywheel plant availability. The amount of time that the flywheel is available to provide regulation affects the total profit that can be realized during the year. Because flywheel storage is modular, equipment diversity should result in high reliability. For example, a Beacon's 20-MW, commercial-scale plant is expected to comprise a few hundred flywheels.

Although not included in the financial analysis, additional benefits derived from the use of flywheels for regulation may include a reduced need for generation capacity, reduced fuel use for generation, reduced air emissions from generation, and reduced generation equipment wear-and-tear.

As an indication of the prospects for reducing air emissions, consider results from a study performed by KEMA, Inc (kema.com), shown in Table E-1. Based on study results, flywheels used for regulation in California could reduce CO_2 emissions by 26% when compared to pumped hydroelectric storage, 53% if the flywheels replace baseload gas-fired generation and 59% if a natural gas-fired peaking generator is displaced. Similarly, (NO_x) emissions may also reduced by 20% to nearly 50%.[E6]

Table E-1. Air Emissions Reduction Potential

Flywheel Emission Savings Over 20-year Life: CA-ISO					
	Coal		Natural Gas		Pumped Hydro
	Baseload	Peaker	Baseload	Peaker	
CO2					
Flywheel	91,079	91,079	91,079	91,079	91,079
Alternate Gen.	322,009	608,354	194,534	223,997	123,577
Savings (Flywheel)	230,930	517,274	103,455	132,917	32,498
Percent Savings	72%	85%	53%	59%	26%
SO2					
Flywheel	63	63	63	63	63
Alternate Gen.	1,103	2,803	0	0	85
Savings (Flywheel)	1,041	2,741	-63	-63	23
Percent Savings	94%	98%	n/a	n/a	27%
NOx					
Flywheel	64	64	64	64	64
Alternate Gen.	499	1,269	80	118	87
Savings (Flywheel)	435	1,205	16	54	23
Percent Savings	87%	95%	20%	46%	26%

Flywheel Energy Storage Cost and Performance

The values shown in Table E-2 are flywheel storage system cost and performance assumptions plus the price for make-up energy (energy required to make up for storage losses). The cost and performance values for flywheels reflect expected values for a 20-MW commercial-scale plant. Installed cost reflects a 20% uncertainty adder. This value is used to account for the normal uncertainty associated with technology scale-up and commercial project development (*e.g.,* siting, contracts, construction delays, *etc*.).

Table E-2. Flywheel Storage Cost and Performance Assumptions

Criterion	Value
Commercial Plant Scale (MW)	20
Plant Installed Cost ($/kW)	1,566
Plant Availability	0.95
Roundtrip Efficiency	81%
Variable Operartion Cost ($/MWh$_{out}$)	3.14
Fixed Operation Cost ($/kW, Year 1)	11.60
Makeup Energy Price ($/MWh)	40

Price for Regulation Service

The key data used for estimating the regulation benefit is the hourly price for up and down regulation services. The price is denominated in $/MW per hour of service. There are two prices for the hour: up regulation and down regulation. Hourly prices for up and down regulation in California in 2006 are shown in Figure E-1 and , respectively. Annual average prices used for the valuation are $21.48/MW and $15.33/MW per service hour for up and for down regulation, respectively, for a total of $36.70/MW per service hour.

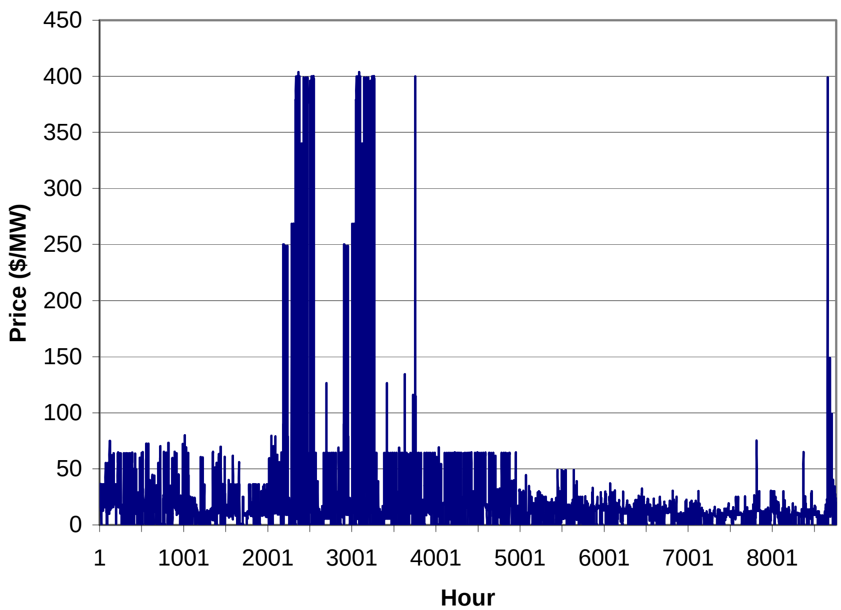

Figure E-1. Up regulation prices in California, 2006.

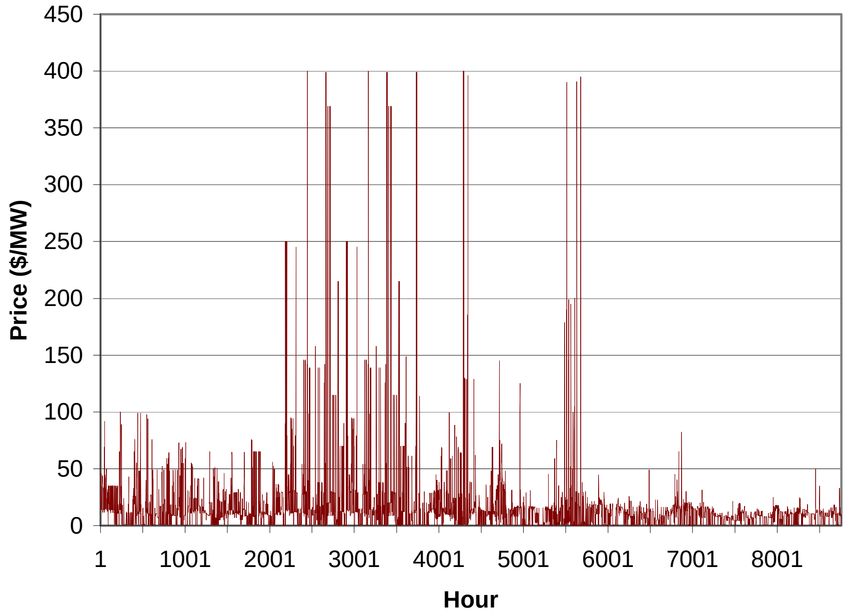

Figure E-2. Down regulation prices in California, 2006.

Value of Regulation from Flywheels

As described elsewhere in this appendix, it is assumed that flywheels used for regulation provide twice as much benefit (to the grid) as generation-based regulation. Specifically, it is assumed that regulation resources are twice as valuable if they follow the area control error (ACE) signal closely. That signal changes every several seconds to reflect the momentary difference between the amount of power that is online and the amount needed to keep supply and demand balanced and to maintain the electrical stability of the grid (especially the 60-Hz AC frequency). Based on this assumption, flywheel storage used as a regulation resource is treated as if it is eligible for payments that are twice as much as the prices shown above for conventional, generation-based regulation.

Market Potential

In addition to financials, the CEC's Public Interest Energy Research Program is interested in the market potential (in MW) for the flywheels-for-regulation value proposition. Unfortunately, the authors of this guide do not have the resources needed to establish that value rigorously or credibly. Nonetheless, the authors speculate that a conservative estimate of the market potential in California could be on the order of 50 to 60 MW of the total regulation market managed by the CAISO over the next 10 years. (The CAISO does not manage all of the regulation resources within the state. Some of that capacity could be in play as well.) This speculation has two primary bases. The first is a very cursory review of regulation capacity requirements available at the CAISO Open Access Same-time Information System website (http://oasis.caiso.com/, under the ancillary services tab). The second is a discussion with representatives from Beacon Power.[E7]

Financial Assumptions

The financial analysis used to calculate lifecycle cost and benefits include a 2.5% annual price escalation and a 10% discount rate. The annual plant carrying cost is calculated by applying an annualization factor (*i.e.*, a fixed charge rate) of 0.20 (*e.g.*, annual financial carrying charges for a $1 million plant = $200,000/year).

Results

Demonstration plant availability for three plant output levels (relative to full rating) is summarized in Table E-3. Also shown is the availability assumed for a commercial plant. As shown in the table, the demonstration unit operated 51.4% of the time at full capacity (full capacity means that all seven flywheels were operating). Similarly, the demonstration unit operated nearly 53% of the time at 85.7% of rated capacity (85.7% capacity represents six flywheels of seven). There were at least five of seven flywheels (71.4% of full rated capacity) operating almost 88% of the time.

Also shown is that the demonstration plant's availability would be somewhat higher when accounting for research-related outages. Research-related outages include downtime due to causes that would only affect operation of a research or pilot project (*e.g.,* no control signal was available, access to the demonstration facility was restricted, or the system could not be connected to the grid). Downtime to due equipment failure is *not* considered a research-related outage.

Table E-3. Demonstration Plant Actual Availability and Commercial Plant Expected Availability

Capacity (% of full)	Availability (Actual)	Without "Research-related" Outages	Commercial Plant (expected)
100%	47.3%	51.4%	95.0%
85.7%	52.7%	56.9%	
71.4%	87.8%	92.0%	

The financial implications of plant availability are summarized inFigure E-3. In the figure, the left axis shows $/kW in Year 1. The axis on the right indicates the corresponding lifecycle value, over the 10-year life assumed for the plant. Results are shown for three levels of annual average power output: 71%, 86%, and 100% of plant rating (note that these values correspond to those shown in Table E-3, rounded to the nearest full percentage point). An output of 71% represents 5 of 7 flywheels in the demonstration system, 86% represents 6 of 7 flywheels, and 100% represents 7 of 7 flywheels. Results are presented, for each of those three plant output levels, for a range of plant annual availability levels. Also shown is the break-even amount, reflecting the carrying cost for a commercial plant.

The uppermost plot indicates results for plants operating at full rating. The next two plots indicate financials for a plant operating at 86% and 71% of its rating, respectively. Thicker parts (to the lower left) of the three plots reflect results from the demonstration. Endpoints on all three plots indicate financials for a plant operating at the respective portion of rated output, if the plant operates as much as a commercial plant is expected to operate (*i.e.*, 95% of the year, full-load equivalent). The box in the upper right indicates financials that would be expected for a commercial plant, based on assumptions provided in Section 3 of this guide. The financial benefit/cost ratio for such a plant ranges

from \$500/kW benefits ÷ \$313/kW breakeven = 1.6

up to \$554/kW benefits ÷ \$313/kW breakeven = 1.77.

Note that plant designers expect a 20-year service life for a 20-MW, commercial-scale plant, although the assumed service life for this report is 10 years. To account for the difference, the present worth of additional benefits increases by about 50%.

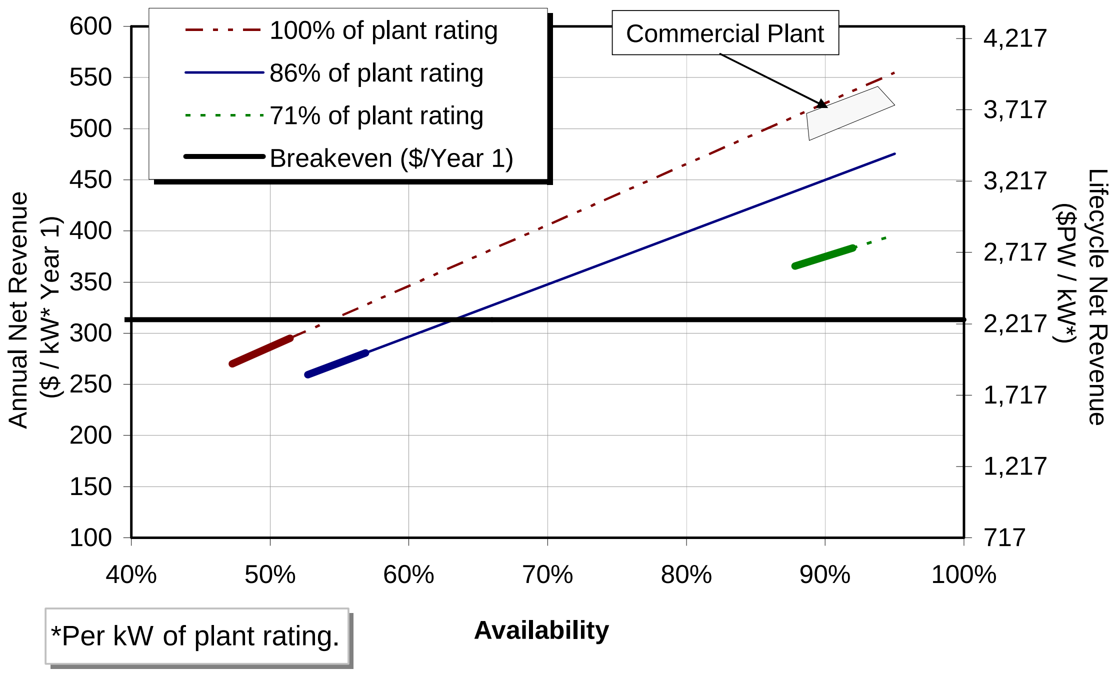

Figure E-3. First-year and lifecycle net revenue, with breakeven indicator.

Methodology Observations and Caveats

- The make-up energy price assumed was not developed rigorously. Although this value is adequate for this analysis, it should be established using a more rigorous approach when evaluating the financials for an actual project.
- Based on results from the demonstration project, flywheel systems with 15 minutes of storage can store enough energy to provide regulation during 97.5% of the time that the storage is used. For the purpose of this evaluation, the financial implications of that criterion are assumed to be modest and are ignored.
- The project was a demonstration of the flywheel's ability to respond to rapidly changing control signals without regard to the magnitude of the response (in MW) that might be needed. Consequently, the results reflect the value for regulation capacity on the margin.

- The market potential estimate used for this evaluation, although adequate for a high-level estimate of the magnitude of statewide economic impact, is imprecise. Unfortunately, little is known about the effect significant penetration of rapid-response regulation capacity will have on the need for regulation and on the price for regulation.
- The premise about how much more valuable flywheels are than generation-based regulation resources, as meritorious as it may be, may not be reflected in regulation pricing without a significant amount of confirmation, regulatory accommodation, and time.
- The 0.20 annualization factor used to estimate the annual carrying cost for the plant, though perhaps imprecise, does provide a reasonable general indication of the cost to finance the plant and equipment using non-utility capital.
- Another important assumption affecting these results is the 20% uncertainly adder (provided by Beacon Power) that increases the assumed installed cost for a commercial plant. That value is used to account for the myriad unforeseen challenges that are likely to beset *any* technology development enterprise and project development effort.
- The design service life for a commercial Beacon Power flywheel plant is 20 years; however, the assumed service life for the evaluation described in this report is 10 years. The reason for this is twofold. First, guidelines established by the CEC's Public Interest Energy Research Program for evaluating the merits of various storage demonstrations require the use of standard assumptions as bases for comparing financials for all demonstration projects sponsored. Those standard assumptions include a 10-year life, a 10% discount rate, and a 2.5 % price escalation rate. Second, while the authors do not refute the 20-year expected life assumed by Beacon Power, a more conservative 10-year life expectancy was used because both the technology and the value proposition are so new.

Conclusions

Perhaps the most important result from the Beacon flywheel demonstration is that the sponsors and vendors successfully demonstrated the ability of the flywheel to follow control signals that change very rapidly, much more rapidly than the signal used to control the output of generation-based regulation. The results indicated that the characteristics of high-speed flywheel storage are generally consistent with a possible new class of regulation resources – rapid-response energy storage-based regulation – in California. In short, it was demonstrated that high-speed flywheel storage systems are capable of following a rapidly changing (every 4 seconds) control signal (the ACE).

Based on these results and on the expected plant cost and performance, high-speed flywheel storage systems have a good chance of being a financially viable regulation resource. The results indicated a benefit/cost ratio of 1.6 to 1.8 using somewhat conservative assumptions. The results also indicated that flywheel systems with 15 minutes of storage can store enough energy to provide regulation during 97.5% of the time that the storage is used.

The market potential (in MW) is less certain. Uncertainty about technical market potential is driven in part by a lack of knowledge regarding how the use of rapid-response regulation resources on the margin will affect overall demand and prices for regulation. Regarding market share, there is always uncertainty regarding competing options (*e.g.,* other vendors/developers and other technologies or approaches).

R&D Needs and Opportunities

One compelling question for this value proposition is–*How much of this resource could be used and how much will be used?* Consistent with the hypothesis that rapid-response storage is twice as valuable as generation-based regulation capacity, another hypothesis to test is that only half as much regulation is needed if all regulation is rapid-response. Increased penetration of rapid-response regulation also means that *generation* capacity is freed to provide power or other more valuable ancillary services and less pollution will be produced and less fuel will be used per MWh delivered. Another way to broach the question is–*What are the key implications for the grid if all regulation is provided entirely by rapid-response regulation?* Those implications include impacts on: the amount of regulation needed, the total cost to ratepayers for regulation, fuel use, and air emissions from generation.

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Available at: http://www.ornl.gov/sci/btc/apps/Restructuring/regtime.pdf.

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[E4] California Energy Commission Press Release. *California Energy Commission Applauds Beacon Power Upon Reaching Research Goal*. January 10, 2007.

[E5] Makarov, Dr. Yuri. Pacific Northwest National Laboratory in conjunction with the CAISO. *Relative Regulation Capacity Value of the Flywheel Energy Storage Resource*. The research was initially commissioned and funded by the CAISO. While the work was in progress, Dr. Makarov left the ISO and later published the report in November 2005.

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[E7] Chet Lyons and Jim Arseneaux, Beacon Power. Discussion with Jim Eyer, Distributed Utility Associates. Mr. Lyons and Mr. Arseneaux indicated that discussions with representatives of various ISOs leads Beacon to assume that market penetration levels of 20% to 25% would have little to modest impact on both the need for regulation and the price paid for regulation. Beacon Power contends that that level is conservative. June 6, 2007.

Appendix F – Energy Prices

This appendix serves two interrelated objectives: 1) provide generic electric energy costs based on a range of fuel conversion efficiencies and fuel costs and 2) provide details about projected wholesale energy prices in California. The California-specific data and figures are based on a California Energy Commission (CEC) forecast for spot electric energy prices in 2009.[F1]

Generic Electric Energy Cost

Figure F-1 and Figure F-2 show generic values for the two key components of unit energy cost: fuel and plant capital cost. Figure F-1 illustrates how fuel price and fuel conversion efficiency affect electricity price. The three plots in the figure represent three conversion efficiency values: 35%, 45%, and 55%.

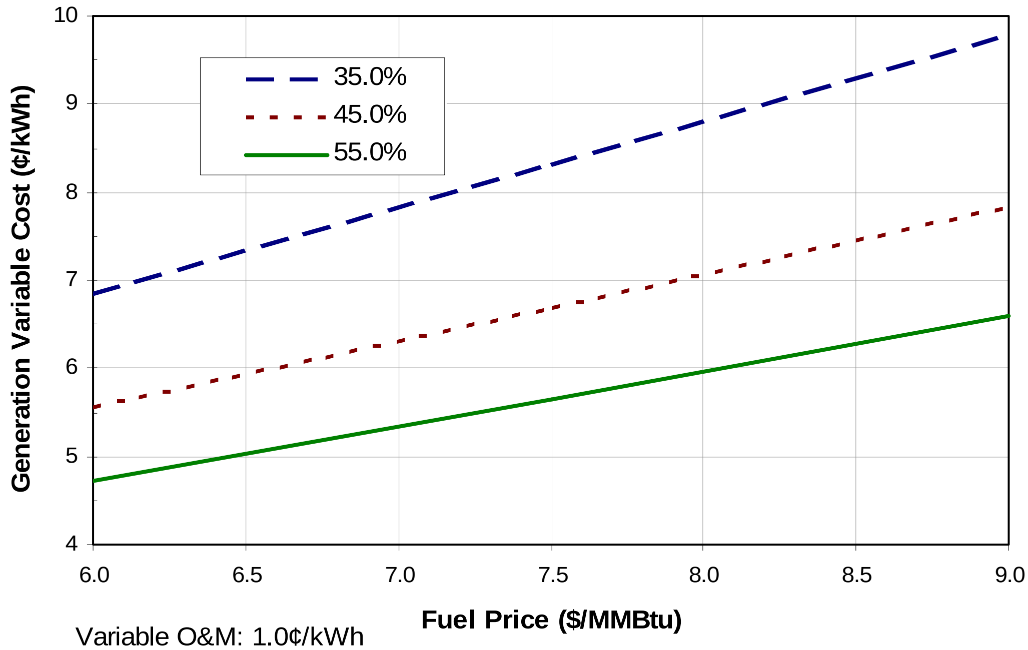

Figure F-1. Generic effect of conversion efficiency and fuel price on electricity price.

Figure F-2 shows how plant capital cost affects the price for electricity. The three plots in this figure represent three generation installed cost values: $400/kW, $1,000/kW, and $1,600/kW. These cost values reflect a generic fixed charge rate of 0.11. To adjust values to reflect a different fixed charge rate, multiply the cost values by the ratio of the actual fixed charge rate by the generic value of 0.11. For example, if the fixed charge rate is 0.13, then multiply the values in Figure F-2 by

$$0.13 \div 0.11 = 1.19.$$

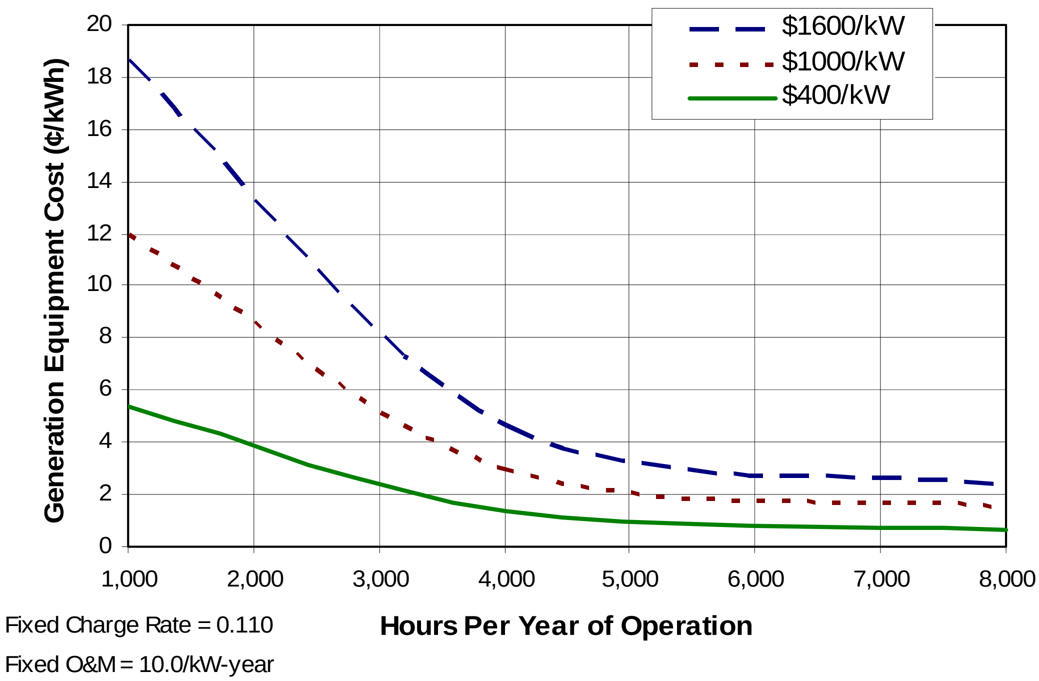

Figure F-2. Generic effect of plant capital cost on electricity price.

California Electric Energy Cost Projection

Figure F-3 shows prices in chronological order, while Figure F-4shows hourly electric energy prices arranged in order of magnitude. In Figure F-4, two plots are shown: one is the actual price and the other is the running average value. The same data, with emphasis on the hours of the years with the highest 10% prices, are shown in Figure F-5.

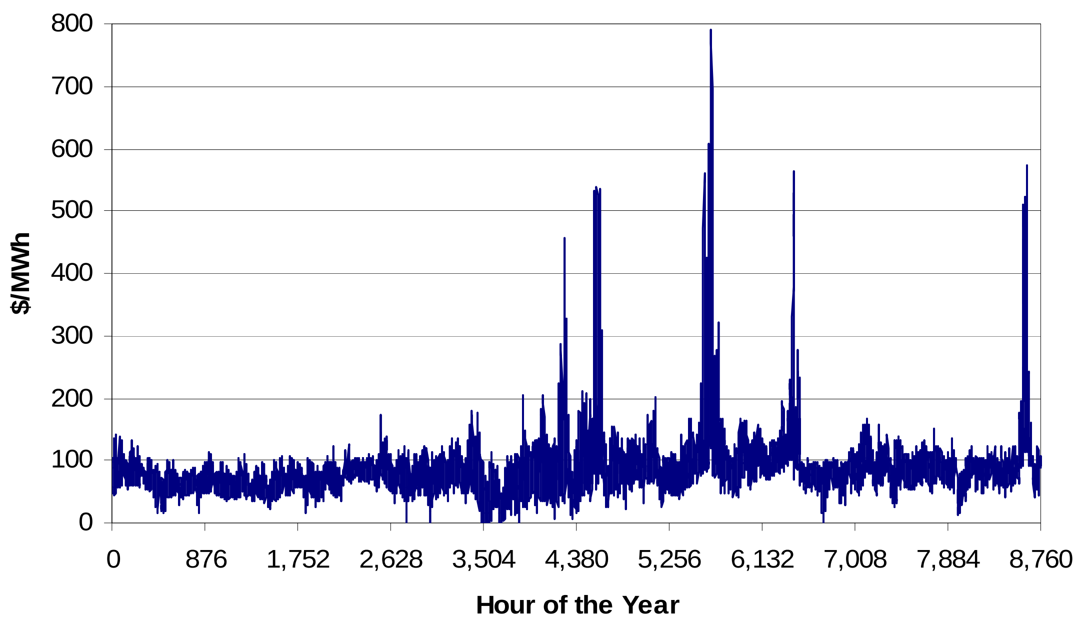

Figure F-3. Electric energy spot prices for California (2009 forecast).

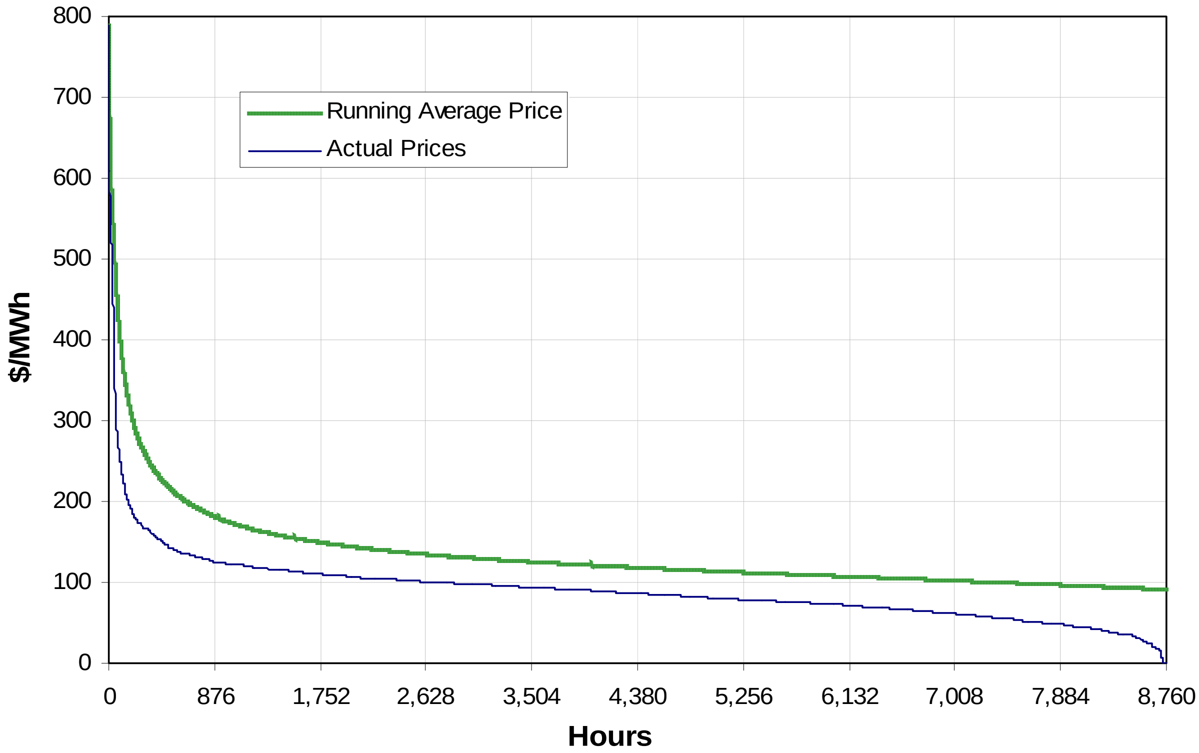

Figure F-4. Price duration curve for California (2009 forecast).

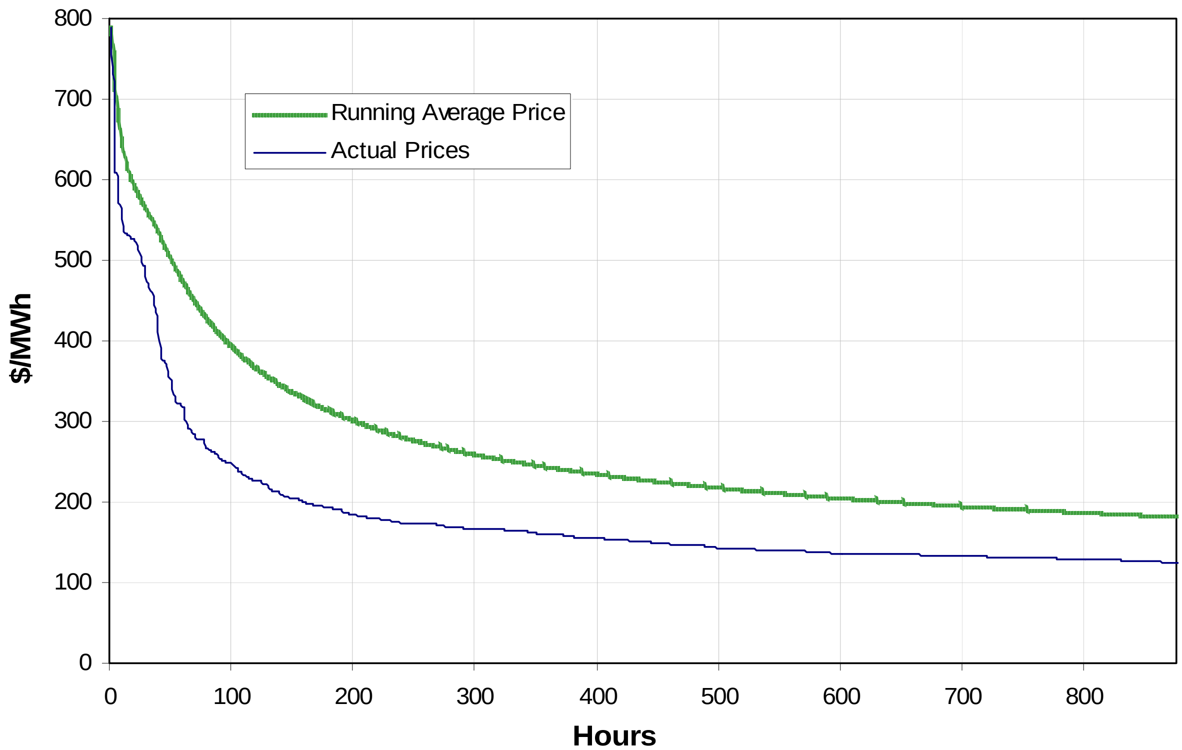

Figure F-5. Price duration curve for California (2009 forecast) 10% highest price hours.

Hourly average prices for each hour of the day for each month are listed in Table F-1. Data in Table F-2 show the net benefit for energy time-shift based on the prices in Table F-1.

Table F-1. Monthly Hourly Average Prices for California 2009 Forecast ($/MWh)

	Month=>											
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	56.4	45.9	50.6	60.1	45.4	41.1	63.9	75.3	82.5	74.7	65.3	76.5
2	49.2	43.5	44.6	57.3	38.1	35.9	56.1	64.8	75.1	61.7	60.4	71.1
3	45.9	41.4	41.5	56.9	35.6	33.6	53.3	63.8	70.5	54.0	56.0	66.7
4	45.9	41.0	41.3	56.7	36.7	31.5	53.0	64.8	73.5	51.3	55.1	64.8
5	51.3	44.3	46.8	62.2	43.2	29.4	54.3	76.2	76.9	57.5	59.8	69.9
6	61.8	50.5	52.7	74.1	57.0	39.7	49.9	73.4	83.4	68.7	72.3	88.8
7	74.0	61.2	62.8	84.0	75.2	59.6	71.7	95.3	97.8	78.7	80.7	89.9
8	81.0	69.0	70.2	89.0	88.9	73.8	85.6	106.2	110.3	89.0	89.5	101.7
9	84.2	72.3	75.2	92.9	93.0	91.2	96.6	112.2	115.4	92.1	98.2	107.2
10	85.5	73.2	78.1	96.4	101.8	102.7	108.9	116.5	119.2	99.7	99.4	102.1
11	85.4	73.3	78.9	96.5	103.0	106.5	117.7	120.1	123.9	102.8	101.4	99.6
12	83.3	72.3	77.9	95.5	102.6	111.2	129.3	132.1	130.7	99.6	101.7	96.8
13	82.1	71.0	77.0	96.1	104.3	120.9	146.0	161.8	139.0	98.1	101.3	93.1
14	80.3	70.3	76.0	94.4	103.3	128.7	165.3	188.5	147.5	100.4	101.3	91.4
15	78.6	68.3	74.0	93.1	103.0	132.4	172.0	203.1	147.6	97.5	99.5	87.4
16	76.0	67.5	71.6	91.4	98.6	128.5	171.5	197.9	144.6	95.5	97.7	87.4
17	80.0	68.6	70.3	89.2	95.6	118.6	163.2	172.8	146.1	96.5	101.6	101.1
18	97.4	79.8	73.9	90.6	92.8	106.9	133.6	136.5	140.3	95.9	115.1	135.2
19	95.7	87.1	91.3	96.9	94.4	98.2	113.0	121.4	142.3	103.6	113.3	132.5
20	90.8	83.1	86.8	105.4	110.5	109.3	121.1	122.4	132.4	105.4	106.5	119.3
21	86.6	76.7	80.0	95.5	94.6	101.7	108.7	111.4	115.5	103.3	102.6	111.7
22	79.7	70.4	73.6	83.4	78.5	79.7	112.4	108.2	104.8	95.7	94.7	102.2
23	73.2	61.5	66.6	69.4	59.4	61.4	80.8	88.3	96.6	88.6	88.4	92.6
24	62.2	49.7	55.3	65.1	55.2	52.4	76.4	82.4	94.5	72.6	71.9	81.9

	Month=>											
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
00 P.M.	85.1	74.5	77.6	94.6	100.3	118.0	148.2	163.1	142.5	99.1	104.5	105.9
00 A.M.	51.8	44.4	46.2	61.2	42.7	35.2	55.1	69.7	77.0	61.3	61.5	72.9
ference	33.3	30.0	31.4	33.4	57.7	82.8	93.1	93.3	65.5	37.8	43.0	33.0

	May - October	November - April
00 P.M.	128.5	90.4
00 A.M.	56.8	56.4
ference	71.7	34.0

Table F-2. Storage Buy-Low / Sell-High Potential for California 2009 Forecast ($/MWh)

Hour	Month=> 1	2	3	4	5	6	7	8	9	10	11	12
12:00 P.M. - 5:00 P.M.	85.1	74.5	77.6	94.6	100.3	118.0	148.2	163.1	142.5	99.1	104.5	105.9
1:00 A.M. - 6:00 A.M.	51.8	44.4	46.2	61.2	42.7	35.2	55.1	69.7	77.0	61.3	61.5	72.9
Storage Losses	10.4	8.9	9.2	12.2	8.5	7.0	11.0	13.9	15.4	12.3	12.3	14.6
Net	23.0	21.1	22.1	21.1	49.1	75.7	82.1	79.4	50.1	25.5	30.7	18.4

	May - October	November - April
12:00 P.M. - 5:00 P.M.	128.5	90.4
1:00 A.M. - 6:00 A.M.	56.8	56.4
Storage Losses*	11.4	11.3
Net	60.3	22.8

*Storage Efficiency = 80.0%

	Hours	Value*
Summer	651.8	39,323
Winter	651.8	14,830
Total	1,304	54,152

*Storage Efficiency = 80.0%

References

[F1] Derived from preliminary Wholesale Electricity Price Forecast data provided by Joel Klein, California Energy Commission. April 2008.

Appendix G – Challenges for Storage

A spectrum of challenges may affect prospects for increased use and acceptance of storage. A high-level characterization of those challenges is provided in this appendix. The purpose for this is to provide storage advocates and other interested stakeholders with a general indication of and awareness about the types of challenges that may arise for any given storage project, and more broadly, that may require attention before storage can be widely deployed. (Note that some of the items listed below are also described as opportunity drivers in Section 7.3.)

- Storage has a relatively high cost.
- Storage energy losses – 20% to 40% of energy stored is lost:
  - Storage tends to have round-trip efficiency of 60% to 80%
- ‘Inefficient’ electric energy and services pricing:
  - Transmission and possibly distribution
  - Demand
  - Energy
  - Reliability
- Limited risk/reward sharing mechanisms between a) utilities and utility customers and b) utilities and third parties:
  - Regulatory rules and ‘permission’
  - Interconnect
  - Undetermined optimal and/or maximum storage penetration levels
    - bulk/central
    - modular/distributed
  - Operations
- Permitting and siting rules and regulations (many have yet to be developed):
  - Zoning and building codes
  - City and community planning
  - Fire, public health, and safety-related rules and codes (mostly local)
  - National Electric Code
  - Occupational safety and health (state and federal agencies)

- Limited familiarity, knowledge, and experience base:
    - Storage cost and benefits
    - Storage technology
    - Storage system integration
    - Distributed energy resources
    - Integration of storage with the grid
    - Storage benefits and value
- Existing utility technology biases (especially utilities and, to a lesser extent, regulators):
    - Utilities are technologically risk averse, for understandable reasons
    - Perceived risk for *any* new technology
- Limited engineering standards and evaluation methodologies.
- Lack of evaluation tools:
    - Electrical
    - Financial
- Financing of ‘new’ technology is challenging:
    - Unknown operational costs
    - Uncertain system life
    - Multi-year payback is difficult for commercial/residential
    - Multi-year payback is acceptable for government and utilities
- Investor-owned utilities’ (IOUs’) preference for *investments* in *equipment* and their aversion to expense-based alternatives (such as rentals, leases or incentives):
    - IOUs derive all profit from *investments* in *equipment*
    - IOUS will tend to avoid *expenses* related to storage involving equipment rental or leases and possibly ‘risk and reward sharing’
    - IOUS will prefer to purchase storage *equipment* though financial justification will often be elusive
- Inadequate infrastructure features and ‘hooks’:
    - Interconnection
    - Control
    - Communication
    - Price signals

- Many technologies, concepts and programs ‘competing’ for ‘attention’:
    - Renewables
        - Waste and biofuels
        - Solar thermal
        - Photovoltaics
        - Wind generation
    - Conventional fuels
        - Clean coal
        - Advanced nuclear
    - Demand response
    - Distributed resources
    - Load aggregation
    - Smart Grid
    - Conservation and efficiency
- Coordinating among numerous stakeholders, for ‘permission’ to use grid-connected storage and/or to aggregate benefits may be expensive and time-consuming.

Appendix H – Distribution

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Sandia National Laboratories

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 62:

Reference(s): D1/T7/S1

Please provide a summary for the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from CWIP.

RESPONSE:

Please see Appendices A and B of this Schedule.

THESL has attempted to reproduce 2005 and 2006 actual numbers shown in Appendix A in the format requested. It is, however, important to note that the 2005 and 2006 "actuals" are depicted in the requested categories with some imprecision as THESL did not track costs in these portfolios at that time.

For the data presented in Appendix B, THESL simply does not have the historical data in the format requested readily available for the 2004-2007 period.

APPENDIX A
Interrogatory Response
Summary of Capital Budget ($ millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
1	OPERATIONAL INVESTMENTS							
2	Sustaining Capital							
3	Underground Direct Buried	2.7	7.3	33.0	23.8	31.9	65.2	62.6
4	Underground Rehabilitation	30.6	33.1	35.7	38.2	36.7	32.1	49.8
5	Overhead	28.3	19.0	24.3	19.3	20.5	22.0	46.8
6	Network	6.4	5.6	9.9	4.7	5.0	5.5	15.1
7	Transformer Station	1.6	0.8	15.9	8.5	8.6	11.9	14.3
8	Municipal Substation Investment	4.7	6.0	6.2	8.3	5.5	6.8	8.2
9	Total Sustaining Capital	74.2	71.8	125.0	102.9	108.2	143.6	196.8
10	Reactive Work	8.2	11.1	15.6	19.3	20.7	19.4	22.2
11	Customer Connections	35.1	36.4	41.7	42.8	37.6	32.4	41.8
12	Customer Capital Contribution	(29.2)	(23.6)	(27.0)	(32.7)	(23.4)	(15.4)	(16.7)
13	Capital Contributions to HONI	0.7	2.6	0.3	0.4	0.3	2.8	15.0
14	Engineering Capital	15.2	21.0	20.7	26.4	25.8	30.9	39.4
15	AFUDC	-	-	3.4	2.0	2.8	4.8	6.6
16	Other	-	-	1.3	(4.3)	3.1	-	2.7
17	Total Operations	104.1	119.3	181.0	156.8	175.1	218.4	307.7
18	GENERAL PLANT							
19	Fleet &Equipment Services	4.8	6.2	9.2	7.9	9.9	9.9	13.3
20	Facilities	2.7	5.7	20.0	3.4	7.6	11.9	13.2
21	Other	5.2	5.9	4.2	0.3	3.2	3.1	2.7
22	Total GENERAL PLANT	12.7	17.8	33.3	11.6	20.7	24.9	29.3
23	CUSTOMER SERVICES							
24	Wholesale Metering	-	1.5	-	4.4	(0.5)	6.9	4.9
25	Smart Metering				5.6	2.6	-	12.6
26	Suite Metering	-	-	-	2.7	3.3	2.4	2.6
27	Other	7.4	3.6	4.6	0.5	0.3	0.6	0.5
28	Total CUSTOMER SERVICES	7.4	5.1	4.6	13.2	5.6	9.9	20.6
29								
30		2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
31	Total INFORMATION TECHNOLOGY	8.1	15.2	20.4	24.1	35.7	28.8	32.8
32	Total OPERATIONAL INVESTMENTS	132.3	157.4	239.3	205.7	237.1	281.9	390.4
33								
34	EMERGING REQUIREMENTS							
35	Standardization	-	-	-	-	5.7	25.9	4.7
36	Downtown Contingency	-	-	-	-	-	13.1	5.4
37	FESI 7 / WPF	-	-	-	-	-	5.5	10.9
38	Smart Grid	-	-	-	-	-	3.0	1.3
39	Externally Initiated Plant Relocations	-	-	-	-	-	-	12.2
40	Stations System Enhancements	-	-	-	-	(1.0)	15.2	33.1
41	Secondary Upgrade	-	-	-	-	-	6.5	10.0
42	Energy Storage Project	-	-	-	-	-	-	30.0
43								
44	Total EMERGING REQUIREMENTS	-	-	-		4.7	69.2	107.7
45	TOTAL CAPITAL	132.3	157.4	239.3	205.7	241.7	351.1	498.0

APPENDIX B

Interrogatory Response

Additions and Deductions from CWIP by Asset Class ($millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		FY08 Actual Jan CWIP Open Balance	**FY08 Actual Dec Cum CWIP Additions**	**FY08 Actual Dec Cum CWIP Transfer to Asset**	**FY08 Actual Dec CWIP Closing Balance**
1	Land_and_Buildings	1.2	1.0	2.1	0.0
2	TS_Primary Above 50	-	0.4	-	0.4
3	Distribution Stn Equip	18.5	21.8	34.2	6.0
4	Poles_Wires	63.2	126.0	147.1	42.1
5	Line_Transformers	9.0	31.0	35.2	4.8
6	Services_and_Meters	1.6	37.8	35.6	3.8
7	Asset - General Plant	2.5	1.8	2.7	1.7
8	Equipmnt	11.6	10.5	14.9	7.2
9	IT_Assets	20.5	29.9	27.2	23.2
10	CDM_Expenditures and Recoveries	-	-	-	-
11	Other_Distribution Assets	4.5	2.6	6.7	0.4
12	Contributions and Grants - Credits	(8.9)	(30.6)	(23.0)	(16.5)
13	Non_Distribution Asset	-	-	-	-
14	Non_Asset	6.5	2.1	-	8.5
15		130.1	234.3	282.8	81.7
16	Net Expenditures	-	-	(48.4)	105.9
17					
18					
19					
20		**FY09**	**FY09**	**FY09**	**FY09**
21		**Actual**	**Actual**	**Actual**	**Actual**
22		**Jan**	**Dec**	**Dec**	**Dec**
23		**CWIP Open Balance**	**Cum CWIP Additions**	**Cum CWIP Transfer to Asset**	**CWIP Closing Balance**
24					
25	Land_and_Buildings	0.0	2.1	0.0	2.1
26	TS_Primary Above 50	0.4	0.5	-	0.9
27	Distribution Stn Equip	6.0	11.4	15.6	1.8
28	Poles_Wires	42.1	143.0	114.7	70.5
29	Line_Transformers	4.8	39.2	31.0	13.1
30	Services_and_Meters	3.8	39.3	36.0	7.2
31	Asset - General Plant	1.7	4.1	1.1	4.7
32	Equipmnt	7.2	17.9	15.8	9.2
33	IT_Assets	23.2	29.5	14.2	38.6
34	CDM_Expenditures and Recoveries	-	-	-	-
35	Other_Distribution Assets	0.4	1.9	1.91	0.4
36	Contributions and Grants - Credits	(16.5)	(21.6)	(18.5)	(19.6)
37	Non_Distribution Asset	-	-		-
38	Non_Asset	8.5	(8.5)		-
39		81.7	258.9	211.6	128.9
40	Net Expenditures			47.2	105.3
44					

APPENDIX B

Interrogatory Response

Additions and Deductions from CWIP by Asset Class ($millions)

	FY10 Bridge Jan CWIP Open Balance	**FY10 Bridge Dec Cum CWIP Additions**	**FY10 Bridge Dec Cum CWIP Transfer to Asset**	**FY10 Bridge Dec CWIP Closing Balance**
Land_and_Buildings	2.1	20.2	11.9	10.4
TS_Primary Above 50	0.9	15.5	8.1	8.3
Distribution Stn Equip	1.8	26.2	2.7	25.3
Poles_Wires	70.5	177.4	156.2	91.7
Line_Transformers	13.1	49.8	52.7	10.2
Services_and_Meters	7.2	44.4	45.1	6.5
Asset - General Plant	4.7	11.0	14.5	1.2
Equipmnt	9.2	11.8	18.1	2.8
IT_Assets	38.6	32.1	39.7	31.0
CDM_Expenditures and Recoveries	-	-	-	-
Other_Distribution Assets	0.4	2.2	1.0	1.5
Contributions and Grants - Credits	(19.6)	(15.4)	(28.7)	(6.3)
Non_Distribution Asset	-	-	-	-
Non_Asset	-	-	-	-
	128.9	375.0	321.3	182.7
Net Expenditures			53.8	155.8

	FY11 TEST Jan CWIP Open Balance	**FY11 TEST Dec Cum CWIP Additions**	**FY11 TEST Dec Cum CWIP Transfer to Asset**	**FY11 TEST Dec CWIP Closing Balance**
Land_and_Buildings	10.4	5.0	10.9	4.5
TS_Primary Above 50	8.3	47.2	23.6	31.9
Distribution Stn Equip	25.3	23.7	13.6	35.4
Poles_Wires	91.7	270.3	219.5	142.4
Line_Transformers	10.2	38.8	36.4	12.6
Services_and_Meters	6.5	35.2	35.5	6.1
Asset - General Plant	1.2	7.5	8.0	0.6
Equipmnt	2.8	16.3	18.6	0.5
IT_Assets	31.0	33.8	43.1	21.8
CDM_Expenditures and Recoveries	-	-	-	-
Other_Distribution Assets	1.5	31.8	2.4	30.9
Contributions and Grants - Credits	(6.3)	(12.6)	(14.6)	(4.2)
Non_Distribution Asset	-	-	-	-
Non_Asset	-	-	-	-
	182.7	496.8	397.1	282.4
Net Expenditures			99.7	232.5

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 63:

Reference(s): D1/ T7/ S1

Please provide a Capital Projects Table as shown in Appendix 2-A of the Filing Requirements.

RESPONSE:

THESL has an extensive capital program with hundreds of individual projects, each of which impacts a number of USoA accounts. THESL's finance system translates the operational categories used by the business units into USoA accounts but the costs are aggregated. The one-to-one relationship between a project and the affected USoA account is not preserved and it would be an enormous undertaking to reproduce the costs in the format of Appendix 2-A in the Board's Filing Requirements.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 64:

Reference(s): C1/ T6/ S1/p. 14

This section discusses THESL's asset management approach. It is stated that:

"As part of the commitment to PAS-55, THESL undertook an internal audit and gap analysis to compare current practices with the requirements of the standard. The audit highlighted two key areas where practices could be improved: mid- to long-term strategy and policy and overall risk management system (especially risk assessment). Much of THESL's asset management development in the last two years – particularly FIM and AIS – has been to improve performance in these areas."

Please state the nature of the deficiencies identified in the internal audit and gap analysis for each of the referenced two key areas and how THESL's asset management development has addressed these areas.

RESPONSE:

From the internal audit and gap assessment, THESL had identified mid-term and long-term strategy and policy, as well as the overall risk management system, as two areas that can be improved based on the following:

- Enhanced alignment between project plans and key strategic areas
- Established processes for prioritizing and optimizing portfolio investments
- Systematic framework for identifying, quantifying and managing operational risks

In response, THESL had committed resources to investigate and improve on asset management plans and system strategies, where required. Accordingly, FIM and AIS are

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

decision-support tools that reflect the recent efforts THESL has made to incorporate a risk assessment framework, and gauge alignment to the organizational strategic pillars when developing and prioritizing projects. THESL will continue to revisit its asset management strategies as needed, and identify available opportunities to build on these decision-support tools.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 65:

Reference(s): D1/ T8/ S1/pp.4-

On these pages, THESL describes its relatively poor ranking in a Reliability Peer Group Study of eight comparable cities. Please describe the impact of THESL's capital investment in 2010 on its service reliability and provide Service Quality Indicators to date. Please provide the comparable data for 2009 actual.

RESPONSE:

As the 2010 THESL capital program is being executed in 2010 it may not have immediate impacts (in 2010) on the service reliability measures such as;

- SAIDI
- SAIFI
- CAIDI

These measures are positively impacted by long sustaining investments and THESL is still in the early stages of its extensive capital program.

The 2010 12-month Rolling actual are attached as Appendix A to this Schedule.

The 2009 Service Quality Measure can be found in the following attachment of our submission document Exhibit B1, Tab 13, Schedule 1.

TH-Electric System Limited
OEB Reliability and Service Quality Measures
Monthly Report

Toronto Hydro-Electric System Limited
Ontario Energy Board Service Quality and Reliability Measures Report
October 2010

Measure		Description	THESL Standard	Oct-2010		12-Month Rolling / Year to Date	
				Monthly		12-Month Rolling	
				Actual	% Variance	Actual	% Variance
SAIDI	(w MEDs)	(minutes)	82	**6.90**	N/A	**106.99**	**(23.4%)**
SAIFI	(w MEDs)	(interruptions per customer)	2.1	**0.21**	N/A	**2.13**	**(1.5%)**
CAIDI	(w MEDs)	(minutes)	48	**33.12**	N/A	**50.16**	**(4.3%)**
SAIDI	(w MEDs; w/o loss of supply)	(minutes)	82	**6.90**	N/A	**87.29**	**(6.1%)**
SAIFI	(w MEDs; w/o loss of supply)	(interruptions per customer)	2.1	**0.21**	N/A	**1.66**	**26.3%**
CAIDI	(w MEDs; w/o loss of supply)	(minutes)	48	**33.12**	N/A	**52.49**	**(8.6%)**
			OEB Standard	Monthly		YTD From Jan-2010	
				Actual	% Variance	Actual	% Variance
NEW SERVICE CONNECTIONS							
	<750 Volts	% connected w/i 5 days	90%	**96.35%**	**7.06%**	**96.31%**	**7.01%**
	>750 Volts	% connected w/i 10 days	90%	**100.00%**	**11.11%**	**99.07%**	**10.07%**
APPOINTMENT SCHEDULING							
	Customer						
	CCM	% scheduled w/i 5 days & 4 hours	90%	96.45%	7.16%	97.90%	8.78%
	Field Services (meter read)	% scheduled w/i 5 days & 4 hours	90%	99.44%	10.49%	99.57%	10.63%
	UG Cable Locates	% scheduled w/i 5 days & 4 hours	90%	100.00%	11.11%	100.00%	11.11%
	Non-Customer						
	CCM	% scheduled w/i 5 days	90%	88.84%	(1.3%)	95.99%	6.65%
	UG Cable Locates	% scheduled w/i 5 days	90%	96.17%	6.85%	97.12%	7.91%
	TOTAL		90%	**95.62%**	**6.25%**	**97.15%**	**7.95%**
APPOINTMENTS MET							
	CCM	% met w/i 4hours	90%	100.00%	11.11%	99.99%	11.10%
	Field Services (meter read)	% met w/i 4hours	90%	99.44%	10.49%	99.57%	10.63%
	Field Services (meter change)	% met w/i 4hours	90%	100.00%	11.11%	99.94%	11.04%
	Meter Services	% met w/i 4hours	90%	100.00%	11.11%	99.83%	10.92%
	UG Cable Locates	% met w/i 4hours	90%	100.00%	11.11%	100.00%	11.11%
	TOTAL		90%	**99.92%**	**11.02%**	**99.90%**	**11.00%**
APPOINTMENT RESCHEDULING							
	CCM	% called back & resched w/i 1 day	100%	100.00%	0.00%	100.00%	0.00%
	Field Services (meter read)	% called back & resched w/i 1 day	100%	100.00%	0.00%	100.00%	0.00%
	Field Services (meter change)	% called back & resched w/i 1 day	100%	100.00%	0.00%	100.00%	0.00%
	Meter Services	% called back & resched w/i 1 day	100%	100.00%	0.00%	100.00%	0.00%
	UG Cable Locates	% called back & resched w/i 1 day	100%	100.00%	0.00%	100.00%	0.00%
	TOTAL		100%	**100.00%**	**0.00%**	**100.00%**	**0.00%**
TELEPHONE ACCESSIBILITY		% answered w/i 30 seconds	65%	**58.93%**	**(9.3%)**	**71.63%**	**10.20%**
TELEPHONE CALL ABANDON RATE		% calls dropped after 30 seconds	<10%	**3.56%**	**64.37%**	**2.51%**	**74.92%**
WRITTEN INQUIRY RESPONSE							
	CCM	% w/i 10 days	80%	98.34%	22.93%	97.34%	21.67%
	Customer Care	% w/i 10 days	80%	94.99%	18.74%	98.46%	23.07%
	TOTAL		80%	**95.50%**	**19.38%**	**98.31%**	**22.88%**
EMERGENCY RESPONSE		% w/i 1 hour	80%	**94.19%**	**17.7%**	**81.56%**	**1.9%**

Contact: Anna-Christina Crespo, Regulatory Affairs, 22755

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 66:

Reference(s): D1/ T8/ S3-2/p.8

THESL states that total installed costs for customer connections is expected to rise about 25 percent between the Bridge and Test years, which is attributable to an increase in residential construction activities and the removal of the Enhancement Cost from THESL's economic model.

Table 3 "Customer Connections and Costs" shows an increase from $32.4 million in the 2010 Bridge year to $41.8 million in the 2011 Test year, a $9.4 million, or 29% increase.

a) Please provide a breakdown of this increase between the two factors discussed, specifically the increase in residential construction activities and the removal of the Enhancement Cost from THESL's economic model.
b) Please provide the percentage of the total amount of the increase due to residential construction activities if the Enhancement Cost had not been removed from THESL's economic model.
c) Please provide further explanation as to why the Enhancement Cost was removed from THESL's economic model and discuss its impact on customer connection costs and the reasons for these impacts.

RESPONSE:

a) The increase between the 2010 Bridge year and the 2011 Test year amount is 100% directly related to the projected increase in residential construction activities. One of the major contributors to the increase is related to the Waterfront Toronto Revitalization project.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

b) The percentage increase would have remained at 29% if the Enhancement Cost had not been removed from THESL's economic model. The removal of the Enhancement Cost from THESL's economic model does not affect the gross capital cost.

c) The customer enhancement costs were removed due to OEB amendments to the Distribution System Code (Board File No EB-2009-0077). This will result in smaller capital contribution costs and smaller expansion deposit costs if applicable.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 67:

Reference(s): D1/ T8/ S1/p. 15

Please provide an itemized breakdown of Underground Rehabilitation capital expenditures for the past five historical years, the bridge year and the test year.

RESPONSE:

The portfolio structure within the sustaining capital program was established in 2007 and first reported in THESL's 2008 EDR. As such, there are no directly comparable figures at the portfolio level before 2007. THESL has made efforts to reconstruct, with some imprecision, 2006 actuals and presented them here as well along with the bridge year and the test year amounts:

2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
33.1	31.3	38.2	36.7	32.1	49.8

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INTERROGATORY 68:

Reference(s): D1/ T8/ S1/p. 19

Please provide an itemized breakdown of overhead capital expenditures for the past five historical years, the bridge year and the test year.

RESPONSE:

Please refer to Appendix A to this Schedule. Please note that due to the volume of projects, a threshold of $500k is applied. THESL does not have five years of comparable historical information at the portfolio level.

Appendix A

	Col. 1	Col. 2	Col. 3
	2008 Table 1 PORTFOLIO 3: Overhead Systems		
	Project Number	Project Title	Historical Cost ($ millions)
1	P0041172	Nomenclature - MANS projects	2.2
2	P0036907	W6086 Keele/Runnymede Conversion Ph 3	1.6
3	P0038674	E08033 Jones Pape B14E:6-8HW OH VC	1.5
4	P0038744	E08215 SCADA SWITCHES BELL TO WIRELESS	1.2
5	P0038893	W08131 85M5 Sheppard/Allen OH Ext	0.9
6	P0038963	E08229 DOHME HF1-2-3 OH VC	0.9
7	P0038698	E08245 Pape B6HW OH VC	0.9
8	P0040379	W08267 Dolomite/Magnetic 85M6 OH CND	0.9
9	P0045098	W8209 St Clair Phase 3 Secondary Cabling	0.8
10	P0044584	BATHURST ST PH2 [DC]	0.7
11	P0039485	W8210 St Clair/Silverthorn 27.6KV OH	0.6
12	P0041381	W08195 TTC Line & Equip Transfers	0.6
13		Others	6.6
	Portfolio Total ($ millions)		19.3

	2009 Table 2 PORTFOLIO 3: Overhead Systems		
	Project Number	Project Title	Historical Cost ($ millions)
14	P0049590	W09251 HL - EGLINTON MS 4KV OH VC	3.4
15	P0047425	E09183 Seymour Baird B8,B6 HW OH VC	1.8
16	P0045098	W8209 St Clair Phase 3 Secondary Cabling	1.6
17	P0050021	E09237 MILLWOOD RD (BAYVIEW -SOUTHVALE)	1.6
18	P0047362	E08050 SCADA MATE SWITCHES INSTALLATION	1.2
19	P0047353	E09240Coxwell Plains DF1-2-3 OH	1.1
20	P0050026	E09262 MILLWOOD U.G. REBUILD / A21-22L	1.0
21	P0047744	W09251 Eglinton MS OH VC Stage 1 Ph 1	0.8
22	P0050144	DC_E08070_07 Leaside Cont UG DX Fdr New	0.6
23	P0055008	W09431 Transformer Smart Metering	0.5
24	P0055010	W09431 Transformer Smart Metering	0.5
25	P0047822	E08114 Pole Replacement NE Area	0.5
26		Others	5.9
	Portfolio Total ($ millions)		20.5

Appendix A

	Col. 1	Col. 2	Col. 3
	2010 Table 3 PORTFOLIO 3: Overhead Systems		
	Project Number	Project Title	Estimated Cost ($ millions)
27	14964	14964_001 W09101 Rearlot Forest Hill Ph2 Electric	3.0
28	16293	16293_001 W10103 Nomenclature	2.2
29	13015	13015_001 IPHE E09232 Donlands Greenwood B3HW OH	1.5
30	12574	12574_001 W09189 Queen St OH VC	1.3
31	13043	13043_005 W09238 Windermere 38M29 ext VC PH1	1.1
32	11321	11321_002 W08191 Bathurst St 35M4(M6)/M9 ENCH	1.0
33	16709	16709_005 W10296 Defectivce Pole Repl	1.0
34	16470	16470_001 HLE_Eglinton MS 4kV OH Stage#2 PH#2	0.8
35	16466	16466_001 HLE_Eglinton MS 4kV OH Stage#2 PH#1	0.8
36	16521	16521_001 W07366 Rearlot Dist Forest Hill Ph1 Remo	0.8
37	17022	17022_001 W09251 HL - Eglinton MS 4kV OH VC	0.8
38	16610	16610_001 E08023 Fortrose 53M26 OH Rebuild	0.8
39	16614	16614_005 W10272 Overhead Line Relocation and VC	0.6
40	16168	16168_001 RC 4360 2010 edr Woodbine29M31 OH [50%]	0.6
41	13605	13605_005 W09099 New SCADA SW OH/UG North York	0.5
42		Others	5.1
		Portfolio Total ($ millions)	**22.0**

	2011 Table 4 PORTFOLIO 3: Overhead Systems		
	Project Number	Project Title	Estimated Cost ($ millions)
43	18808	Runnymede TS 11M8 (Overhead Rebuild)	5.2
44	18758	X12054 Voltage Conversation from 4kV to 13.8kV System TOB5DN	5.1
45	18888	X11359 Runnymede TS (11M8) Rogers Rd, Keele to Boone Ave.	3.5
46	18413	E11360 Rebuild Saunders King VC	2.4
47	18388	E11333 Rebuild Brimley Anson VC PEF1	2.2
48	18731	ORC Keele/Wilson Site Fdr 2 Electrical Wilmington, Faywood, Wilson, Keel	2.2
49	18729	ORC Keele/Wilson Site Fdr 1 Electrical Combe, Rimrock, Sheppard, Keele,	1.9
50	18168	W11192 Eglinton MS VC Stage 3 B3-5EG	1.9
51	17996	W10096 O'Hara St OH VC	1.8
52	18629	X11422 Hazelwood B7HW conversion TOB7HW	1.5
53	19202	W11490 Transformer Smart Metering PH#1 2011	1.3
54	19227	W11492 Transformer Smart Metering PH#2 2011	1.3
55	19228	W11493 Transformer Smart Metering PH#3 2011	1.3
56	19229	W11494 Transformer Smart Metering PH#4 2011	1.3
57	18656	E11383 Livingston Guildwood Part 2 OH VC	0.8
58	18853	X11361 Runnymede TS (11M8) Dunraven Dr/Blackthorne	0.8
59	18900	W11149 North York Remote Switch Replacement - Finch TS Feeders	0.7
60	18850	X11329 Runnymede TS (11M8) Caledonia Rd/North of Rogers Ave	0.7
61	18328	E11243 NY 80M6 Feeder OH Enhancement NY80M6	0.5
62		Others	10.6
		Portfolio Total ($ millions)	**46.8**

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INTERROGATORY 69:

Reference(s): D1/ T8/ S1

Please provide an itemized breakdown of network capital expenditures for the past five historical years, the bridge year and the test year.

RESPONSE:

Please refer to Appendix A to this Schedule. Please note that due to the volume of projects, a threshold of $100K is applied. THESL does not have five years of comparable historical information at the portfolio level.

Appendix A

2008 Table 1 Portfolio 4: Network

	Col. 1	Col. 2	Col. 3
	Project Number	Project Title	Historical Cost ($ millions)
1	P0039602	N08208-1TX -4310 TX Emergency Loc 1	0.3
2	P0039817	N08148-5ATS Loc#4613 RR 282 ST CLAIR W	0.2
3	P0038169	N7124 High Level Birch to Balmoral Civil	0.2
4	P0031438	N07091-REACTIVE N/W UNIT REPL 1 OF 2	0.2
5	P0039261	N08146-12TX - Hogarth -adj #10	0.1
6	P0039273	N08145-10TX - Simcoe- n/ Queen	0.1
7	P0039815	N08148-4ATS - Loc#D3021 Wade Ave adj #20	0.1
8	P0039811	N08148-2ATS LOC#D3007 DUNDAS ST W	0.1
9	P0039285	N08145-5TX - Bond- Dundas	0.1
10	P0039229	N08145-7TX -Albert e/Bay	0.1
11	P0039249	N08145-3TX - Merton -adj 111	0.1
12	P0039305	N08146-6TX - Simcoe- n/ Queen	0.1
13	P0039277	N08145-4TX - Rose- s/ Howard	0.1
14	P0039237	N08145-1TX -Victoria -adj 75	0.1
15	P0039618	N08208-5TX -4360 TX Emergency Loc 2	0.1
16	P0039293	N08147-1TX - Hogarth -adj #10	0.1
17	P0039265	N08145-8TX - Albert -e/Bay	0.1
18	P0039269	N08145-9TX - Bay- s/ Temperance	0.1
19	P0039337	N08147-2TX - Victoria -adj #75	0.1
20	P0039208	N08145-6TX-Chestnut- Queen	0.1
21	P0039341	N08147-5TX - Spadina - College	0.1
22	P0039313	N08146-8TX - Richmond-Duncan	0.1
23	P0039241	N08145-2TX - Lakeshore- Freeland	0.1
24	P0039345	N08147-4TX - Merton - adj #69	0.1
25		Others	1.6
26	Portfolio Total ($ millions)		4.7

2009 Table 2 Portfolio 4: Network

	Project Number	Project Title	Historical Cost ($ millions)
27	P0039813	N08148-3ATS Loc#4320 Adj #130 Merton St	0.2
28	P0048433	N_W09323-18 TX- High Park adj #100	0.2
29	P0050220	N_E09322-21 TX - Bleeker - adj#375	0.2
30	P0048508	N_E09322-17 TX- Dundonald-adj #15	0.2
31	P0050195	N_E09322-07 TX - 743 Pape Ave. TTC	0.2
32	P0048500	N_E09322-02 TX-Lakeshore Freeland	0.2
33	P0050114	W09323-24 -Unplanned-Sick Childrens Hosp	0.2
34	P0050216	N_W09323-03 - Richmond - w/Bay	0.1
35	P0048484	N_W09323-08 TX- Gerrard W adj #33	0.1
36	P0050118	N_W09323-25 TX-700 University Ave	0.1
37	P0048516	N_E09322-19 TX - Jarvis - Isabella	0.1
38	P0048512	N_E09322-18 TX - Bloor-Huntley	0.1
39	P0048504	N_E09322-03 TX- Roxborough-Yonge	0.1
40	P0050640	N_W09323-23 TX - Breadalbane-Yonge	0.1
41	P0050097	N_E09322-25 TX-Spadina & Queen St. West	0.1
42	P0048412	N_W09323-16 TX- Beverley-Dundas	0.1
43	P0050199	N_E09322-20 - Danforth - w/Luttrell	0.1
44	P0048437	N_W09323-19 TX- Spadina - Dundas	0.1
45	P0048441	N_W09323-01 TX- John-Stephanie SV	0.1
46	P0048534	N_E09322-14 TX- 267 Mutual A50CS	0.1
47		Others	2.3
48	Portfolio Total ($ millions)		5.0

Appendix A

2010 Table 3 Portfolio 4: Network

	Col. 1 Project Number	Col. 2 Project Title	Col. 3 Estimated Cost ($ millions)
49	16503	16503_001 E10810-22TX RC4310	0.1
50	16529	16529_001 W10078-22TX RC4360	0.1
51	16532	16532_001 E10810-26ATS Replacement	0.1
52	16545	16545_001 E10810-27ATS Replacement	0.1
53	16547	16547_001 W10078-26ATS	0.1
54	16548	16548_001 W10078-27ATS	0.1
55	16520	16520_001 W10078-14TX RC4360	0.1
56	16494	16494_001 E10810-13TX RC4310	0.1
57	16495	16495_001 E10810-14TX RC4310	0.1
58	16496	16496_001 E10810-15TX RC4310	0.1
59	16497	16497_001 E10810-16TX RC4310	0.1
60	16498	16498_001 E10810-17TX RC4310	0.1
61	16499	16499_001 E10810-18TX RC4310	0.1
62	16500	16500_001 E10810-19TX RC4310	0.1
63	16501	16501_001 E10810-20TX RC4310	0.1
64	16502	16502_001 E10810-21TX RC4310	0.1
65	16567	16567_001 E10810-25TX RC4310	0.1
66	16522	16522_001 W10078-15TX RC4360	0.1
67	16523	16523_001 W10078-16TX RC4360	0.1
68	16524	16524_001 W10078-17TX RC4360	0.1
69	16525	16525_001 W10078-18TX RC4360	0.1
70	16526	16526_001 W10078-19TX RC4360	0.1
71	16527	16527_001 W10078-20TX RC4360	0.1
72	16528	16528_001 W10078-21TX RC4360	0.1
73	16569	16569_001 W10078-25TX RC4360	0.1
74	16431	16431_001 DC_E09322-24 Emg TX Repl 2010	0.1
75	16432	16432_001 DC_E09322-25 Emg TX Repl 2010	0.1
76	16433	16433_001 DC_W09323-24 Emg TX Repl 2010	0.1
77	16434	16434_001 DC_W09323-25 Emg TX Repl 2010	0.1
78		Others	2.3
79		**Portfolio Total ($ millions)**	**5.5**

2011 Table 4 Portfolio 4: Network

	Project Number	Project Title	Estimated Cost ($ millions)
80	19033	X11487 Vault Rebuild, Loc#4312, King St. West/Yonge St.	2.3
81	18834	X11234 Location # 4481, Eglinton Avenue East/ Holly St.	1.6
82	18838	X11245 St. Clair/ Yonge St. Location #4541 A55H	0.9
83	18837	X11441 Vault Relocate, Loc#4512 Holly/Eglinton Ave. East	0.9
84	18968	X11481 Vault Relocate, Loc #4438 St. Patrick St./Queen St. West A65WR	0.9
85	18912	X11390 Network Replacement, Loc#4407	0.8
86	18836	X11440 Vault Relocate, Loc#4642 St. Clair Ave. W/Yonge St.	0.8
87		Others	6.9
88		**Portfolio Total ($ millions)**	**15.1**

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INTERROGATORY 70:

Reference(s): **D2/ T1/ S1/pp.1-2**

Table 1: "THESL Capital Contributions to HONI" shows a capital contribution to HONI for the Leaside-Birch TS project of $13.0 million in the 2011 test year. THESL states that this project is now expected to be completed in 2013.

a) Please provide a detailed explanation as to how this capital contribution will impact the revenue requirement in the 2011 test year.
b) Please provide THESL's estimate as to total costs for the project which it will incur to completion as well as the projected capital contributions for 2012 and 2013.

RESPONSE:

a) Capital contributions to Hydro One attract the incremental revenue requirement of a pure capital expenditure (there are no associated operating expenditures). As such, the capital contribution enters ratebase after application of the half year rule and drives incremental revenue requirement related to amortization, the weighted average cost of capital, and PILs. This capital contribution to Hydro One will be amortized over 25 years.

b) Hydro One has provided a draft Capital Cost Recovery Agreement to THESL in October 2010. It contains the payment schedule for the period from 2010 to 2013. In addition, costs for an environmental assessment study were incurred in 2008 and 2009 and these were also paid to Hydro One. The costs are in Table 1 below:

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Table 1: Historical and Projected Costs ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2012 Forecast	2013 Forecast
Capital Contribution	$0.4	$0.342	$0.458	$12.1	$17.6	$15.278
Total Cost	$0.4	$0.342	$0.458	$12.1	$17.6	$15.278

The projected total capital contributions to Hydro One for this project are $46.178 million. There are no other THESL costs for this project and therefore the capital contributions represent the entire project cost to THESL.

It should be noted that Table 1 of Exhibit D2, Tab 1, Schedule 1 contains an error in the 2008 Actual column for the Leaside-Birch project. The $ (4.9) million is incorrect and should be $0.4 million as indicated above.

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INTERROGATORY 71:

Reference(s): D1/ T8/ S1/p.26

A description of capital expenditures for Transformer Stations is found in this exhibit. On page 26, THESL proposes a $5.7 million or 66.3% increase in capital investment for transformer stations over 2009 Historical.

Please provide an itemized breakdown of transformer station capital investments for the past five historical years, the bridge year and the test year including a percentage breakdown for each component of transformer station investment.

RESPONSE:

Table 1 is an itemized breakdown of transformer station capital investments, as described in Exhibit D1, Tab 8, Schedule 1 for the past five historical years, the bridge year and the test year.

Table 1: Transformer Station Capital Investments 2005-2010 ($millions)

	2005 Historical	2006 Historical	2007 Historical	2008 Historical	2009 Historical	2010 Bridge	2011 Test
Switchgear	0.3	0.1	12.1	7.4	8.4	11.5	11.7
Circuit Breaker	0.2	0.9	0.7	0.4	0.2	0.0	1.3
RTU (SCADA)	0.4	0.3	0.8	0.1	0.0	0.0	0
Miscellaneous	0.9	0.4	0.2	0.6	0.0	0.4	1.3
Total	1.8	1.7	13.8	8.5	8.6	11.9	14.3

Table 2 is a presentation of the unit counts and percentage of the population of each component due to investments indicated in Table 1. The top number is the number of

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units and the number beneath is a percentage of the population.

Table 2 Percentage of Population for Each Investment

	Population	2005	2006	2007	2008	2009	2010 Bridge	2011 Test
Switch-gear[1]	52 100%	0 0%	0 0%	3 5.8%	1 1.9%	1 1.9%	2 3.8%	2 3.8%
Circuit breaker	737 100%	2 0.3%	17 2.3%	16 2.2%	4 0.5%	2 0.3%	0 0%	7 0.9%
RTU (SCADA)	56 100%	3 5.4%	1 1.8%	3 5.4%	1 1.8%	0 0%	0 0%	0 0%

[1] A 13.8kV indoor metal-clad switchgear replacement will include 14 to 16 circuit breakers.

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INTERROGATORY 72:

Reference(s): D1/ T8/S6-1/p.2

Table 1: “Fleet and Equipment, Tool Crib, Laboratory Capital Program” shows that capital costs for “Total Fleet and Equipment Services” are projected to increase from $9.9 million in 2009 to $13.3 million in the 2011 Test year, an increase of $3.4 million or 34.3%.

THESL states that the increased capital cost for 2011 is required to support further efforts to “green” THESL’s fleet.

a) Please provide a breakdown of the vehicles to be purchased in 2011 and their projected costs, specifying which of these are being purchased related to the green initiative.
b) Please state whether or not THESL undertook any comparative assessments of the costs of the green initiative as compared to purchasing conventional vehicles.
   i. If yes, please state how much of the estimated increase in the 2011 Test year is related to the green initiative.
   ii. If not, please state why not and provide an estimate of the incremental costs.

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RESPONSE:

a)

	Number to be Purchasesd	Price per vehicle	Total Cost	Hybrid or Electric Option?	Approx Premium vs. Conventional	Total Premium by Type
Double Bucket	3	$ 370,000.00	$ 1,110,000			
Single Bucket	16	$ 270,000.00	$ 4,320,000	Y	25%	$ 1,080,000.00
Crane	2	$ 350,000.00	$ 700,000			
Cable	2	$ 400,000.00	$ 800,000			
DERRICK	5	$ 350,000.00	$ 1,750,000			
Dump	1	$ 150,000.00	$ 150,000			
UG Cube	4	$ 110,000.00	$ 440,000			
Van Bucket	1	$ 90,000.00	$ 90,000			
Pick Up	34	$ 40,000.00	$ 1,360,000	Y	30%	$ 408,000.00
Van	33	$ 35,000.00	$ 1,155,000			
Van EV	10	$ 77,000.00	$ 770,000	Y	120%	$ 420,000.00
HSUV	1	$ 40,000.00	$ 40,000	Y	20%	$ 8,000.00
Car	8	$ 40,000.00	$ 320,000	Y	30%	$ 96,000.00
Trailer	3	$ 40,000.00	$ 120,000			
Equip	3	$ 80,000.00	$ 240,000			
	126		**$ 13,365,000**		**Total Premium Paid**	**$ 2,012,000.00**

b) Yes.

i. $2,012,000

ii. N/A

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INTERROGATORY 73:

Reference(s): D1/ T8/ S 8-7

Table 1: “IT Program Cost”, shows a capital expenditure of $1.1 million for a Smart Grid initiative.

THESL states that this initiative will support Smart Grid operations related to Electric Vehicles, Active Demand response and Energy Storage.

Please state whether or not this capital expenditure is incremental to the Smart Grid Plan. If so, please explain why it is not classified as a smart grid expenditure. If not, please clarify how it fits into the smart grid plan.

RESPONSE:

This capital expenditure is not incremental to the Smart Grid Plan, but is included in the $2.4 million capital expenditure as described under Exhibit G1, Tab 1, Schedule 1.

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INTERROGATORY 74:

Reference(s): D1/ T9/ S1/pp.1-2

On page 1, Table 1: "2011 Equipment Standardization Portfolio" shows a decrease of $21 million or 82% of capital spending on standardization over the 2010 bridge year levels.

THESL notes that "The most problematic legacy installations are those installed prior to the amalgamation of the former utilities of Toronto Hydro, Etobicoke Hydro, North York Hydro, Scarborough PUC, East York Hydro and York Hydro into the present day Toronto Hydro, as those are generally more likely to be obsolete and lacking records."

On page 2, THESL states that this variance is due to reclassifying the handwell standardization work as "Secondary Upgrades" and reduced spending on transformer standardization.

a) Please provide further explanation of the decrease referenced above.
b) Please report on the progress of projects in this category in 2010. Please include a status report on the standardization of the problematic legacy installations referenced above.
c) Please provide an itemized breakdown of the costs of all proposed projects in this category.

RESPONSE:

a) The Standardization portfolio in 2010 included:
   - Replacement of metallic handwells, secondary cable and handwell lids
   - SCADA switch installations Transformer replacements

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- Secondary system related work for 2011 was transferred from this portfolio to the secondary upgrades portfolio, primarily because the main driver for the work was public safety related rather than replacement of legacy assets. In addition, the 2011 proposed spending for SCADA switch installations is approximately $10M lower than the 2010 forecast spending. The changes in these two categories represents most of the $21M reduction in this portfolio.

b) See below for an update regarding the 2010 Standardization program.

Project	Scope	2010 Forecast	Variance
Handwell Standardization	Handwell replacements, handwell lid replacements, secondary cable replacements	$14.4	On track
Transformer Standardization	CSP transformer replacements, non-switchable transformer replacements and turtle transformer replacements	$1.8M	On track
Switch and Feeder Lateral Standardization	Installation of SCADA-ready O/H switches, PMH switches and fuses	$9.7M	On track

c) See below for an itemized breakdown of 2011 standardization projects. Note that the total estimated cost is based on existing infrastructure, switching requirements and other location specific parameters.

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PROJECT DESCRIPTION	ESTIMATED COST	UNITS
E10387 Bermondsey Scada Switch install 53M10	$ 602 000	5 O/H Switches, 2 PMH Switches
E10388 Sheppard T.S. OH SCADA Switch Installation SCNT47M7	$ 332 000	4 O/H Switches
E10393 Warden Scada Switch install 43-M-24	$ 514 000	6 O/H Switches
E11088 North York Panacomm SCADA Replacement (East) NY53M10	$ 1 800 000	21 O/H Switches, 3 PMH, 9 vault RTU
X11525 Replacement of manual switch with SCADA, EYA12L	$ 59 000	6 O/H Switches
X11526 Replacemant of manual switch with SCADA, EYA14L	$ 59 000	6 O/H Switches
W11528 CSP Tx Replacement - Finch TS Proj. 1 of 4	$ 178 000	17 CSP Transformers
W11527 CSP Tx Replacement - Finch TS Proj. 2 of 4	$ 247 000	23 CSP Transformers
W11541 CSP Tx Replacement - Finch TS Proj. 3 of 4	$ 214 000	22 CSP Transformers
W11542 CSP Tx Replacement - Finch TS Proj. 4 of 4	$ 216 000	23 CSP Transformers
W11534 CSP TX Replacement Stage #1 NY85M9	$ 165 000	14 CSP Transformers
W11538 CSP TX Replacement Stage #2 NY85M9	$ 242 000	20 CSP Transformers
W11561 CSP Tx Replacement - Finch TS 55M28	$ 259 000	24 CSP Transformers

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INTERROGATORY 75:

Reference(s): D1/ T9/ S3

On Table 2 of page 10, total cost is shown for the FESI7/WPF (Worst Performing Feeders Program) as $10.0 million for the 2011 Test year. This is an increase of $4.5 million or 98% from the 2010 Bridge year.

a) Please provide a detailed breakdown of the categories and projects underlying the number in this table.
b) Please state why THESL considers that FESI 7/WPF is an “emerging requirement” rather than a sustaining capital investment or reactive capital.

RESPONSE:

a) The following is a breakdown of proposed Worst Performing Feeders projects for 2011:
   - $6.35M for replacement of direct-buried cable (including the construction of concrete-encased ducts), replacement of submersible transformers and elbows and replacement of pad-mounted switches with high failure probability.
   - $3.65M for the rebuild of overhead sections of Worst Performing feeders including replacement of poles, installation of new transformers (where current transformer is overloaded), installation of new lightning arresters and switches.

b) Toronto Hydro is working to be more pro-active with respect to capital investments. Though sustaining capital is able to pro-actively invest in the vast majority of our system, failure data indicates that a small group of Worst Performing Feeders has a significant impact on system performance, contributing about 40% to system wide SAIDI and SAIFI.

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The Worst Performing Feeder (“WPF”) list is ascertained by a rolling window of recent equipment failures, thus, new feeders in need of urgent pro-active investment will always be emerging. These failure trends emerge faster than seen on typical feeders for which long-term capital plans are generally developed.

The WPF program is designed to identify these trends and replace assets in a pro-active manner with urgency near that of reactive capital.

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INTERROGATORY 76:

Reference(s): **D1/ T9/ S5-1 and S 5-2**
D1/ T7/ S1, Table 2

Table 1 of the first reference shows a net capital expenditure for Externally Initiated Plant Relocation of $8.0 million. Table 1 of the second reference shows a net capital expenditure of $0. Table 2 of the third reference displays a total capital expenditure of $12.2 million.

a) Please reconcile these three tables and, if necessary, provide any updates to the evidence.

b) Please provide a breakdown of the projects underlying the numbers in these tables for each year shown. Please specify projects for both overhead plant relocations and underground plant relocations and provide start and end dates for each of the projects.

RESPONSE:

a) Table 2 of the third reference is the total Externally Initiated Plant Relocation cost of $12.2 million. It includes $9.7 million (Externally Initiated Plant Relocation – Gross) from Table 1 of the first reference and $2.5 million (Transit City Initiated Plant Relocation – Gross) from Table 1 of the second reference.

b) Please refer to the table below.

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Externally Initiated Projects

Year	Project Description	Type of Work	Start Date	End Date
2011	BRIDGE REHAB	UG/OH	-	-
2011	LOCAL ROAD RECONSTRUCTION	OH	-	-
2011	MAJOR ROAD RECONSTRUCTION	OH/UG	-	-
2011	WATERMAIN REPLACEMENT	OH/UG	-	-
2011	GEORGETOWN CORRIDOR EXPANSION - GO TRANSIT	OH/UG	-	-
2011	STRACHAN AVENUE RAIL CROSSING - GO TRANSIT	OH/UG	-	-
2011	YORK UNIVERSITY STATION	UG	-	-
2011	TTC TRACK RECONSTRUCTION	OH/UG	-	-
2011	TTC STATION VENT WORK	UG	-	-
2011	UNPLANNED RELOCATIONS WEST, CENTRE,EAST	OH/UG	-	-
2011	QUEENS QUAY REVITALIZATION	UG	-	-
2010	ST. CLAIR/3 CC ABANDON	UG	July	Dec
2010	BLOOR TRANSFORMATION	UG	Jan	Nov
2010	SPADINA SUBWAY FINCH W STN - PHASE 1 RELOCATION MURRAY ROSS	OH/UG	Jan	Aug
2010	SPIDINA SUBWAY EXT FINCH WEST SUBWAY STATION - TTC - PHASE 2 OH KEELE ST	OH	Apr	Dec
2010	SPIDINA SUBWAY EXT FINCH WEST SUBWAY STATION - TTC - PHASE 3 UG	UG	May	Jan
2010	ALLANFORD/SHEPPARD REF2 RELOCN/VC PHASE 1	OH/UG	Jun	Feb
2010	COLLINGWOOD REF2 RELOCN/VC PHASE 2	OH/UG	Jul	Mar
2010	MOORE ST POLE RELOCATION	OH	May	Jul
2010	PARKLAWN RD WIDENING	OH/UG	May	Sep
2009	ST. CLAIR-PHASE 1,2,3 OUTSTANDING WORK	OH/UG	Jan	Sep
2009	ST. CLAIR - KEELE/GUNNS AREA (ADDITIONAL 3 CC BUILDS)	UG	Apr	Aug
2009	BLOOR TRANSFORMATION-ST. PAULS SQUARE NETWORK	UG	Jun	Aug
2009	BLOOR TRANSFORMATION-VAULTS	UG	Apr	Dec
2009	BLOOR WEST TRANSFORMATION-REC	UG	Jan	Dec
2009	BLOOR EAST & WEST TRANSFORMATION-EXP	UG	Feb	Dec
2008	ST. CLAIR - MAIN FEEDER RUN (STATIONS)	UG	Jan	Mar
2008	ST. CLAIR WESTMOUNT TO CALEDONIA (McRoberts)	OH	Jan	Dec
2008	ST. CLAIR PH-1 (SECONDARY)	OH	Jan	Jul
2008	ST. CLAIR - SILVERTHORN (ROGERS TO ST. CLAIR)	OH	Jan	Dec
2008	ST. CLAIR - LAUGHTON TO GUNNS ENHN	OH	May	Aug
2008	ST. CLAIR SECONDARY PH-2 (CRANG TO WESTMOUNT)	OH/UG	Apr	Dec
2008	ST. CLAIR - CALEDONIA TO GUNNS ROAD PH-3 (CIVIL)	UG	May	Dec
2008	BLOOR TRANSFORMATION - RECOVERABLES	UG	Sep	Dec
2008	BLOOR TRANSFORMATION - EXPANSION	UG	Jul	Oct
2008	ST. CLAIR - U/G 13.8KV SECONDARY (CALEDONIA TO GUNNS ROAD) PH-3	OH/UG	May	Sep

Transit City

2011	TRANSIT CITY FINCH W LRT	OH/UG	-	-
2011	TRANSIT CITY SCARBOROROUGH LRT	OH/UG	-	-
2011	TRANSIT CITY EGLINTON LRT	OH/UG	-	-
2011	TRANSIT CITY SHEPPARD E LRT	OH/UG	-	-
2011	TRANSIT CITY WATERFRONT W LRT	OH/UG	-	-
2010	SHEPPARD LRT	OH/UG	Jan	Dec

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INTERROGATORY 77:

Reference(s): **D1/ T9/ S6**

In this section, THESL discusses a project to develop a new substation, Bremner TS. THESL states that this site is currently owned by HONI and that THESL will be the station developer. On page 5, Footnote 1 states that station costs include land, building, substation equipment and distribution system modification costs.

a) Please clarify the respective roles and ultimate ownership of the development, by explaining what system elements are being constructed by Hydro One.

b) On page 5, Table 1 "Estimated Capital Costs" shows capital contribution to HONI totalling $20.4 million by 2013. Please explain which elements of this project require capital contributions and why.

c) Please state whether or not the contribution of $20.4 million constitutes the whole cost of Hydro One's investment or not.

d) Given that distribution asset voltage goes as high as 50 kV and THESL's evidence states that Bremner TS goes above this level, please provide an explanation as to why this asset should be considered a distribution asset.

e) Please indicate whether THESL is planning to apply to have this asset classified as a distribution asset for rate making purposes and when.

f) Please provide a detailed chronology of the project and provide an in-service-date for this asset.

g) Please state whether or not THESL is proposing to incorporate any costs related to this project into rate base in this application or at any time prior to the asset being used and useful. If THESL is making such a proposal, please provide the justification for it and whether THESL is proposing similar treatment for any other assets in the

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present application. If there are no other assets for which similar treatment is being requested, please explain why this asset should be treated differently.

RESPONSE:

a) Hydro One will be providing the 115kV supply connection between their John x Esplanade transmission cable circuits and the THESL-owned 115kV switchgear at the proposed Bremner TS. All other elements will be constructed by THESL and its contractors. THESL intends to own all elements it constructs.

b) The estimated capital contribution to Hydro One will be required for Hydro One to carry out design and installation of the 115kV cable circuit connection between their John x Esplanade circuits and the proposed Bremner TS. THESL will be exploring carrying out this work itself, after considering regulatory and cost issues. These issues include the classification of the transmission line work and the costs of Hydro One relative to independent contractors for the same.

c) The estimated capital contribution of $20.4 million is the forecasted amount THESL will be paying to Hydro One for the connection of the station to the 115kV grid. HONI will not be investing in the station itself.

d) THESL does not request that assets operating at voltages above 50kV be considered distribution assets generally or that the definitions be changed. However, the Board can deem transmission assets to be distribution assets for the purposes of ratemaking. The final EDR Rate Handbook provides as follows at page 25:

> "A distributor wishing to have any assets included in the distribution rate base that would not be included in the definition of the distribution rate

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base, as specified in Appendix A (e.g. Account 1815 Transformer Station Equipment – normally primary above 50 kV), should request in the summary of the application that the Board, in its decision on the application, deem such assets to be distribution assets."

e) THESL does plan to request that the Board deem the Bremner Station to be a distribution asset on or before the date that the station is forecast to come into service.

f) The planned major milestones are:

- August 2011 – design complete
- August 2012 – building construction complete
- March 2013 – commissioning commences
- July 2013 – in-service

g) Capital contributions to HONI, pursuant to the 2006 EDR Handbook and the TSC are the only costs capitalized prior to energization.

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INTERROGATORY 78:

Reference(s): D1/ T9/ S7

Table 1: "Secondary Upgrade" shows a total capital expenditure of $10.0 million in the 2011 Test year. THESL states that for 2011, the scope of work includes excavation and removal of abandoned handwells; replacement of active handwells with non-conductive units; replacement of underground secondary mains cable with a superior, dual-insulation cable and remaking all connections in handwells to the current standard.

a) Please provide an itemized breakdown of the costs of the various components of this program.
b) Please state the total number of handwells that need to be replaced and the number that will be replaced in each year of the program.
c) Please state the number of years it will take to complete this program.
d) Does THESL anticipate that the implementation of this program results in a reduction of THESL's ongoing contact voltage scanning costs? If yes, please state by how much and when. If not, please explain why not.

RESPONSE:

a) For 2011, THESL estimates that a total of 2100 handwells will be replaced. The estimated costs are expected to include $8.4M for civil work (excavation of existing handwell, new handwell installation) and $1.6M for electrical work (cable replacement and re-making of connections).

b) THESL is prioritizing areas in the former city of Toronto for this work, based on the general condition of the assets, the number of handwells in the area and the volume of pedestrian traffic. Based on existing data, THESL expects to replace roughly 2100

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handwells in 2011 and roughly 1750 handwells in 2012. Additionally, handwells in the remaining areas of the city may be replaced in 2013 and beyond.

c) It is expected to take three years to address the former city of Toronto (including 2010).

d) No, THESL does not anticipate that the implementation of this program results in a reduction of THESL's ongoing contact voltage scanning costs in the short term because the scanning costs are for the numbers of scans over the entire City regardless of how many contact voltage incidents are found. In the longer term, the need for the frequency of scanning will be re-evaluated based on experience, number of incidents and asset condition.

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INTERROGATORY 79:

Reference(s): D1/T14/ S1
J1/T2/S4

Table 1 of the first reference provides THESL's working capital allowance for the years 2009 Historical, 2010 Approved, 2010 Bridge and 2011 Test.

The second reference provides a breakdown of the working capital calculation for the 2011 Test year.

a) Please confirm that THESL has not updated its lead-lag study that was filed in EB-2007-0680. If not confirmed, please provide the updated study

b) Please provide a detailed explanation of the calculations in the second reference, including how the working capital factors are calculated and, what is meant by "Net Lag Days," and what the values for these days are in the 2011 Test year.

c) Please provide supporting calculations for the years shown in table format. Please include the commodity price, wholesale market service charge, uniform transmission rates and all other rates and purchase levels used in the calculations.

RESPONSE:

a) Confirmed. The lead-lag study has not been updated. The model has been modified to include HST, and the inputs to the model reflect the test year costs.

b) "Net Lag Days" are the billing lag for the average number of days from the date the meter is read until the customer is billed. In the lead-lag study, it was determined that the average billing lag was 16.17 days. For further details please see the attached

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Lead Lag Report by Navigant Consulting, labelled Appendix A to this Schedule. The Net Lag Days from that report is the basis for the 2011 test year.

c) Please see attached tables for Working Capital Allowance calculations, labelled Appendices B and C.

Toronto Hydro-Electric System Limited
EB-2010-0142
Exhibit R1
Tab 1
Schedule 79
Appendix A
Filed: 2010 Dec 6
(23 pages)

REPORT ON LEAD LAG STUDY AND WORKING CAPITAL RESULTS USING 2005 EXPENSE LEVELS

Presented to:

Toronto Hydro Electric System Limited

December 4, 2006

Prepared by:

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TABLE OF CONTENTS

I. INTRODUCTION

In 2006, the Ontario Energy Board ("OEB") issued a directive to Toronto Hydro Electric System Limited ("THESL" or the "Company") requesting that the Company conduct a study of its lead/lag methodology to support its future working capital submissions before the OEB[1]. In response to the directive, the Company retained Navigant Consulting, Inc. ("NCI") to perform a lead/lag study using the most recent data available and to derive THESL's working capital requirements for the historical 2005 "test" year. The purpose of this report is to provide the results of the lead-lag study and to determine the working capital requirements of the Company's distribution business.

I.A. Working Capital and Lead/Lag Studies

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility. The determination of working capital generally relies on a lead/lag study.

A lead/lag study analyzes the time elapsed between the date customers receive service and the date that such customers' payments are available to the Company (or "lag") together with the time during which the Company receives goods and services but pays for them at a later date (or "lead"). "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of the Company's rate base.

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[1] EB-2005-0421, Decision With Reasons, Issued April 12, 2006

Performing a lead/lag study requires two key undertakings: a) developing an understanding of how the regulated business works in terms of collections and payment policies and procedures; and b) development of a representative data set that reflects the implementation of such policies and procedures in terms of the timing of payments received (sent) at any given point in time.

To develop an understanding of THESL's operations, interviews with personnel within the regulated utility's Accounts Payable, Customer Service, Human Resources, Payroll, and Tax Departments were conducted. As in prior instances where NCI has conducted lead/lag studies, some key issues that were addressed during the course of the interviews included:

- The nature of buyers (sellers) within the business;
- The nature of the product or service, i.e., what is being sold (or bought), or, if a service was being provided;
- The time period over which the service was provided;
- Payment Terms, i.e., whether driven by government mandate, industry norms, or by company policy and the degree of flexibility within the terms for payment;
- Actual payment dates and amounts;
- Method of payment for such products (or services), e.g., cash, check, electronic;
- Expectation of changes (if any) to the Company's collections and payment policies or procedures going-forward.[2]

Operational data was obtained from THESL's Accounts Payable, Customer Service, Human Resource, Payroll, and Tax Systems. Once the data had been gathered, sampling and data validation was performed to the extent necessary and appropriate. Data validation generally took the form of comparing an actual invoice or a bill with data from the Company's systems to ensure accuracy. Except where otherwise noted,

[2] Activity over a given twelve month period is used to analyze the timing of payments and receipts unless interviews with Company personnel reveal that there are known changes to existing policies or procedures going forward. Where such changes are known, they have been incorporated into the derivation of the appropriate leads, lags, and net lags.

the lead-lag study focused on activities within THESL for the twelve months ended August 31, 2006.

I.B Organization of the Report

Section II of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of revenues and how they were treated for the purposes of deriving an overall revenue lag for the Company's distribution operations.

Section III presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads is the lead-time on OM&A costs, interest on long-term debt, Payments in Lieu of Taxes (such as Capital, Income, and Large Corporation Taxes), and the Goods and Services Tax (or "GST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section IV sets forth a summary of THESL's working capital requirements for its distribution operations using operating expense data for the historical 2005 year.

II. REVENUE LAGS

A utility providing service to its customers generally derives its revenue from the services provided to its customers. Revenue lags represent the number of days from the date services are rendered by the Company until the date payments are received from the customers and such funds are available to the Company. Based on a review of the Company's accounting records, NCI has determined that the majority of THESL's revenues originate from two sources:

1. Residential Class, various General Service Classes, and Large User Class customers, hereafter referred to as "Bundled service ratepayers";
2. Other (miscellaneous) sources including (but not limited to) retailers, connection charges, transformer rentals and customer related jobs.

When both sources of revenues are considered together, the weighted average revenue lag time is 71.53 days. Table II-1 shows the amount of these revenues in 2005, the revenue lags associated with each revenue source, and the weighted average of all revenue sources.

Table II-1

THESL Revenue Lag

Source of Revenues	Revenue Lag (Days)	2005 Amounts (Mil $s)	Weighting Factor	Weighted Revenue Lag
Revenues from Bundled Service Ratepayers	71.76	2,687	99.17%	71.16
Revenues from Other Sources	44.66	22	0.83%	0.37
Total		2,709	100.00%	71.53

II-A. Revenues from Bundled Service Ratepayers

As shown in Table II-1, revenues from bundled service ratepayers represented 99.17% of total revenues realized by the Company during 2005. The lag time associated with the realization of such revenues was 71.76 days.

The lag associated with the Company's provision of service to its bundled service ratepayers typically consists of four components: a) Service lag; b) Billing lag; c) Collections lag; and, d) the lag associated with the Company's payment processing lag (including bank float). The contribution of each component to the overall revenue lag is shown in Table II-2, below.

Table II-2

Revenue Lag from Bundled Service Ratepayers (Days)

Revenue Lag Component	Days
Service Lag:	27.10
Billing Lag:	16.17
Collections Lag:	27.06
Payment Processing & Bank Float Lag:	1.43
Total	71.76

A discussion of each of the four components follows.

II.A.1 Service Lag

The Service Lag covers the period between the time the Company provides service and the time customers' meters are read. Interviews with the Company's customer service personnel revealed that the Company's customers have their meters read on a monthly or bi-monthly basis. Based on this information and using data from the Company's Customer Information System ("CIS") regarding the number of customers that receive monthly and bi-monthly service respectively, NCI determined that the average service lag was 27.10 days.

II.A.2 Billing Lag

The billing lag refers to the average number of days from the date the meter is read until the customer is billed. Based on the Company's monthly scheduled meter read and bill dates, NCI determined an average billing lag of 16.17 days for the twelve months ended August 31, 2006.[3]

II.A.3 Collections Lag

The collections lag refers to the average amount of time from the date the Company mails a bill to the date that THESL receives the customer's payment. For the purpose of this lead/lag study, this information was derived from an aging of accounts receivables report that showed the amount outstanding by aging day interval. Using data for the twelve-month period ended August 31, 2006, an average collections lag time of 27.06 days was derived.

II.A.4 Payment Processing and Bank Float

Based on interviews with the Company's Customer Service Department and the Company's Treasury operations, NCI determined that customer payments to the Company were typically in the form of pre-authorized payments, checks (lockbox), payments via the telephone, payments directly to financial institutions for credit to the Company's bank account, electronic payments (internet payments or direct debit payments), or payments via credit card. Using data on actual payments made and processed for the twelve-month period ended August 31, 2006, NCI determined that the weighted average lead-time associated with payment processing and bank float was 1.43 days.

[3] This average billing lag includes the time period associated with the Company's receipt of billing data from the Ontario Independent Electric System Operator ("IESO") in order to bill its customers.

II.C. Revenues from Other Sources

Revenues from other sources represent 0.83% of the Company's total collections during 2005. The timing of receipts of such other revenues from customers depends on the Company's billing, collections, and payment processing and bank float operations. Thus, a lag time of 44.66 days was used in the derivation of the Company's overall revenue lag time as shown on Table II-1.

III. EXPENSE LEADS (LAGS)

As mentioned at the outset, a lead/lag study considers both the lag time associated with the collection of revenues from customers as well as the lead (or lag) time associated with the payment for goods and services provided to the Company by its vendors. For the purpose of this lead/lag study, the following four broad categories of expenses were considered in order to estimate the overall cash working capital requirement of the Company:

1. Cost of power;
2. Operations, Maintenance, and Administrative ("OM&A") expenses[4];
3. Interest on Long Term debt; and
4. Taxes.

Each of these categories and the associated expense lead (or lag) times are discussed below.

III.A Cost of Power

The Company purchases all of its power supply requirements from Ontario's Independent Electric System Operator (the "IESO"). Based on actual billings and the Company's payments to (or receipts from) the IESO during the twelve month period ended August 31, 2006, a weighted expense lead time of 32.61 days was derived for the cost of power.

This weighted expense lead-time includes an average service lead-time of 15.21 days since the IESO provides service to the Company on a monthly basis. The

[4] The categories included within OM&A expenses are generally consistent with those defined within the Ontario Energy Board's Distribution rates Handbook.

derivation of the expense lead-time associated with the cost of power is shown in Table III-1[5].

Table III-1

Derivation of the Expense Lead Time for Cost of Power

Service Begin	Service End	Service Lead Time	Monthly Payment Amounts	Payment Date	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
9/1/2005	09/30/2005	15.00	200,974,640	10/19/2005	19.00	34.00	10.02%	3.41
10/1/2005	10/31/2005	15.50	184,360,107	11/17/2005	17.00	32.50	9.19%	2.99
11/1/2005	11/30/2005	15.00	161,372,179	12/16/2005	16.00	31.00	8.05%	2.49
12/1/2005	12/31/2005	15.50	202,696,412	1/18/2006	18.00	33.50	10.11%	3.39
1/1/2006	01/31/2006	15.50	162,630,421	2/16/2006	16.00	31.50	8.11%	2.55
2/1/2006	02/28/2006	14.00	156,059,276	3/16/2006	16.00	30.00	7.78%	2.33
3/1/2006	03/31/2006	15.50	86,324,877	4/20/2006	20.00	35.50	4.30%	1.53
4/1/2006	04/30/2006	15.00	138,929,508	5/16/2006	16.00	31.00	6.93%	2.15
5/1/2006	05/31/2006	15.50	169,178,427	6/16/2006	16.00	31.50	8.43%	2.66
6/1/2006	06/30/2006	15.00	165,500,488	7/19/2006	19.00	34.00	8.25%	2.81
7/1/2006	07/31/2006	15.50	184,853,295	8/17/2006	17.00	32.50	9.22%	3.00
8/1/2006	08/31/2006	15.50	192,839,849	9/19/2006	19.00	34.50	9.61%	3.32
			2,005,719,479				100.00%	32.61

[5] By ignoring the IESO creditworthiness requirements when computing the expense lead time associated with the cost of power, the Company has been conservative in estimating the working capital requirement associated with the cost of power. As it stands today, should the Company be downgraded to a BBB rating category, an additional $80 million in letters of credit may need to be posted with the IESO. More importantly, and from a working capital perspective, THESL is subject to margin calls from the IESO. If THESL's "actual exposure" (i.e., the total amount owed to the IESO) crosses a pre-determined threshold, the IESO can and does issue actual margin calls; all margin calls must be paid in cash within 2 business days of the margin call, and must be enough to reduce THESL's actual exposure down to 35% of its "maximum exposure". Margin calls posted are used as offsets against the next IESO invoice. THESL is currently in discussions with the IESO to try and change this with a view to making this less onerous. Should these discussions prove unsuccessful, THESL may have to reflect the IESO practices and recompute the expense lead time (and accompanying working capital requirements) associated with the cost of power.

III.B OM&A Expenses

The next category of expenses considered in the lead/lag study was OM&A expenses. Included within this category were the following types of expenses:

1. Payroll and Benefits;
2. Expenses associated with Consulting and Contract Staff;
3. Lease Expenses;
4. Provincial and Local property taxes; and
5. Miscellaneous Operations and Maintenance expenses.

The expense lead times associated with each type of OM&A expense are discussed below.

III.B.1 Payroll and Benefits

The category "Payroll and Benefits" consists of a number of expense-related items. A summary of the items considered, their individual expense lead times, their corresponding weighting factors, and the overall weighted expense lead time is shown in Table III-2 below.

Table III-2

Payroll and Benefits

	Amounts Twelve Months ended August 31, 2006	Lead (Lag) Days	Weighting Factor	Weighted Lead
Net Payroll - Actives	$76,577,494	11.50	52.30%	6.01
Withholdings - Actives	33,829,038	20.82	23.10%	4.81
Pensions	18,156,050	45.28	12.40%	5.61
Employer Health Tax	2,139,600	30.21	1.46%	0.44
Workers Safety Improvement Board Payments (WSIB)	955,096	45.24	0.65%	0.30
Group Medical and Dental	11,334,337	0.50	7.74%	0.04
Group Life	2,155,568	35.20	1.47%	0.52
Long Term Disability (LTD)	1,176,620	35.19	0.80%	0.28
Accidental Death and Dismemberment (ADD)	24,544	35.21	0.02%	0.01
Employee Assistance Program (EAP)	72,447	35.22	0.05%	0.02
Total	$146,420,793		100.00%	18.04

Each item in Table III-2 is discussed below.

III.B.1.1 Payroll and Payroll Related Withholdings

Based on interviews with the Company's payroll department, NCI determined that:

- All active THESL employees are paid bi-weekly on the same cycle. Payroll administration is outsourced and ADP is the payroll administrator. ADP has access to net payroll funds a day in advance of payday.
- Payroll related taxes and withholdings, on the other hand, are remitted to the respective authorities by THESL.
- All payments are via electronic funds transfer.

Based on this information and taking into account actual pay dates and amounts as well as withholding remittance dates and amounts, an expense lead time of 11.5 days was estimated for active employee payroll and 20.82 days for withholdings associated with active payroll.

III.B.1.2 Pensions

In accordance with the requirements of its pension fund administrator (The Ontario Municipal Employee Retirement System or “OMERS”), the Company is required to make contributions to OMERS on the last day of the month following the month of service. Using actual payment dates and amounts remitted and using a 15.21 day service lead time (the mid-point of the month for which a contribution is due), an overall expense lead time of 45.28 days was derived.

III.B.1.3 Employer Health Tax (“EHT”)

Pursuant to the Income Tax Act, the Company is required to make monthly installment payments associated with the EHT around the middle of the month following the month of service. Taking into account actual remittances made by the Company, the remittance dates, as well as the service periods covered by those remittances, the weighted expense lead-time was calculated to be 30.21 days.

III.B.1.4 WSIB Payments

The Workplace Safety Insurance Board (“WSIB”) oversees Ontario's workplace safety education and training system, provides disability benefits, monitors the quality of health care, and assists in early and safe return to work. The WSIB premium covers workers on a Corporation’s payroll, either working full or part time under a contract of service or as an apprentice. Based upon WSIB coverage periods, and actual payment amounts and dates during the twelve-month period ended August 31, 2006, an expense lead-time of 45.24 days was derived.

III.B.1.5 Group Medical and Dental

During 2005-06, the Company's Health and Dental program was administered by Manulife which charges an administrative fee for services rendered and is reimbursed for claims. The Company paid the administrator daily for both the administration and claims related costs incurred by Manulife. Taking into account actual payments made by the Company, an expense lead-time of 0.5 days was estimated.

III.B.1.6 Group Life, Accidental Death and Dismemberment ("ADD"), Long Term Disability ("LTD"), and Employee Assistance Programs ("EAP")

During 2005-06, the Company's programs were administered by MEARIE, RBC Insurance, SunLife, and Warren Sheppell, which charges premiums or administrative fee for services rendered. Life Insurance premiums and administrative fees for the Company's LTD, ADD, and EAP programs are paid monthly by check typically around the 15th of the month following the month of service. Taking into account actual payments made by the Company during 2005, expense lead time estimates for: a) Group Life is 35.20 days, b) LTD is 35.19 days, c) ADD is 35.21 days, and d) EAP is 35.22 days.

III.B.2 Consulting and Contract Staff

The second type of expense which falls under OM&A expenses are those associated with Consulting and Contract Staff. Using data on invoices from vendors of services provided to the Company, NCI determined that the average expense lead-time associated with payments for consulting and contract staff was 54.78 days. The invoices included a broad spectrum of services ranging from communications and training, contract employee services, building maintenance, and architectural and other consulting related services.

III.B.3 Leases

The third type of expense included under the OM&A umbrella are payments made by the Company for operating leases. The Company leases office space as well as space for its communication antennas. Based on actual payments made for the leases for the twelve months ended August 31, 2006, a weighted expense lead-time of negative 14.71 days was determined.

III.B.4 Property Taxes

The Company makes two forms of property tax payments: a) Payments to the City of Toronto, b) PILS property taxes to the Province of Ontario. Property Taxes were paid to the City of Toronto in six installments during the current year for the current year. The first three payments were estimated and trued up in the second set of three payments. Payments were made by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of negative 28.09 days was determined.

PILS property taxes were paid to the Province of Ontario in two installments. The first was an estimate and the second consisted of a true up as well as the second payment amount. PILS Property Taxes were paid in the current year for the current year and were paid by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of 12.67 days was determined.

III.B.5 Miscellaneous Operations and Maintenance Expenses

Using invoices for routine goods and services provided to the Company, NCI determined a weighted average expense lead-time of 40.08 days for miscellaneous operations and maintenance related expenses. NCI's analysis took into account transactions that occurred during 2005 and, where services were provided to the Company, used the actual service periods shown on vendor invoices.

III.C. Interest on Long Term Debt

The Company has two outstanding long-term debt instruments; both of which were payable to THESL's holding company (Toronto Hydro Corporation or "THC"):

- $980 million at 5 percent. Interest was payable quarterly by THESL to THC on the last day of March, June, September, and December. Payments were made by wire transfer.
- $180 million at 6.16 percent. Interest was due semi-annually on May 7th and November 7th. Payments were made by wire transfer.

Taking this information into account, an expense lead-time of 43.23 days was estimated.

III.D. Taxes

Both income and non-income taxes, as well as pass-through taxes, must be considered in a lead/lag study when deriving working capital requirements. The categories of taxes that were considered in this study were: 1) Payments in Lieu (PIL) of Taxes including the Ontario Capital Tax and the Corporate Income and Large Corporation Tax, 2) the Debt Retirement Charge, and 3) the Goods and Services Tax ("GST").

III.D.1 Payments in Lieu of Taxes (PILs)

The Company paid its current year PILS obligations **(**Capital, Corporate Income, and Large Corporation Tax) to the province of Ontario in monthly installments and made a true up payment in or around February of the following year. Thus, the Company was pre-paying a portion of its annual tax obligation and post-paying the balance. Taking this information into account and using actual payment dates and amounts, an expense lead-time of 37.95 days (dollar-weighted by amount paid by month) was derived.

III.D.2 Debt Retirement Charge ("DRC")

DRC collections by the Company were used to retire the former Ontario Hydro stranded debt. Annual DRC amounts were paid in monthly installments to the Ontario Electric Finance Corporation (OEFC). Such payments are generally made on the 18th of every month for the month prior and are calculated based on prior month billings. Payments were made by wire transfer. Based on actual DRC payments made in 2005, a weighted expense lead-time of 33.2 days was determined.

III.D.3 Goods and Services Tax

The GST is imposed by the Federal Government and is levied at a flat rate of 6 percent. The following categories of GST were considered in this study:

1. Retail Revenues
2. Cost of Power
3. Consulting and Contract Staff
4. Lease Payments
5. Miscellaneous Operations and Maintenance Expenses

III.D.3.1 GST - Retail Revenues

The Company is obligated to collect GST from its customers and remit such collections to the Federal Government. Remittances were generally due on the last day of the month following the month in which a customer is billed for GST. Based on this information, a GST lead-time of negative 18.49 days was determined. The lead-time is shown as negative as such GST amounts which the Company was required to remit represent a source of working capital to the Company.

III.D.3.2 GST – Cost of Power

The Company is owed GST on amounts that it pays on power supplies from the IESO. Similar to retail revenues, a reimbursement generally occurs at the end of the month following the date of payment (or receipt) of funds from the IESO. Using actual dates of payments/receipts, an average expense lead-time of 43.58 days was determined and used in the derivation of the Company's cash working capital requirement.

III.D.3.3 GST – Consulting and Contract Staff

Reimbursements were made on the last day of the month following the dates on which the Company made payments on account of its retaining consulting and contract staff. Taking this information into account and using actual payment dates, an expense lead-time of 44.64 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.4 GST – Lease Payments

Reimbursements were made on the last day of the month following the dates on which the Company made lease payments. Taking this information into account and using actual payment dates, an expense lead-time of 46.68 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.5 GST – Miscellaneous Operations and Maintenance Expenses

As with other categories of GST, using actual payment dates on miscellaneous operations and maintenance expenses, an expense lead-time of 47.16 days was determined.

IV. THESL'S WORKING CAPITAL REQUIREMENTS

This section presents the derivation of the Company's working capital requirements using the revenue lags and expense leads discussed in Sections II and III, respectively. Table IV-1 shows the overall derivation of the Company's cash working capital requirement.[6] Footnotes 1, 2, and 3 to Table IV-1 are provided in support of the information shown in Table IV-1. As shown in Table IV-1, the net cash working capital requirement using 2005 expense levels is $298 million or approximately 12.45 percent of OM&A expenses and the cost of power. As would be expected, the cost of power is the most significant contributor to the Company's net cash working capital requirement followed by OM&A expenses. What drives the magnitude of the requirements is the significance of the net lag (i.e., revenue lag minus the expense lead time) for both these items.

[6] The dollars provided in Column E of Table IV-1, were provided by (and will be addressed by) the Company. NCI has not reviewed, nor have we expressed an opinion as to the accuracy of the figures.

Table IV-1

Calculation of THESL Working Capital Requirement

(All data in Millions $s except where otherwise noted)

	Expense Item Description	**Revenue Lag (Days)**	**Expense lead (Days)**	**Net Lag (Lead) Days**	**Working Capital Factor**	**Expenses at Present Rates**	**Working Capital Requirement**
		(A)	(B)	(C)	(D)	(E)	(F)
1	Cost of Power	71.53	32.61	38.92	10.63%	2,224	236
2	OM&A Expenses	71.53	19.86	51.67	14.12%	167	24
3	Interest on Long term debt	71.53	43.23	28.30	7.73%	81	6
4	Payments in Lieu of Taxes	71.53	37.95	33.58	9.18%	61	6
5	Debt Retirement Charge	71.53	33.20	38.33	10.47%	159	17
6	Sub-Total					2,692	289
7	GST[7]					19	9
8	TOTAL (including GST)					2,711	298
9	**Working Capital as a % of OM&A including Cost of Power**						**12.45%**

[7] See Footnote 1 for calculation.

Footnotes 1, 2, and 3 to Table IV-1

FOOTNOTE 1: GST CALCULATION					
	GST CATEGORY	2005 Expenses (Mil $s)	6% GST	Net Lead (lag) Days	GST Benefit (Cost)
		(A)	(B)	(C)	(D)
1	Revenue	2,709	163	(18.49)	(8)
2	Cost of power	2,224	(133)	43.58	16
3	OM&A Expenses	167	(10)	46.93	1
4	TOTAL		22		9

FOOTNOTE 2: OM&A CALCULATION					
OM&A CATEGORY		Amounts for the 12 months ended 8/31/06 ($000s)	Weighting Factor	Expense Lag Time	Weighted Expense Lead Time
		(A)	(B)	(C)	(D)
1	Payroll and benefit costs	146,421	79.93%	18.04	14.42
2	Consulting and contract staff	2,586	1.41%	54.78	0.77
3	Lease Payments	357	0.20%	(14.71)	(0.03)
4	Property taxes - Province	539	0.29%	12.67	0.04
5	Property taxes - City	7,052	3.85%	(28.09)	(1.08)
6	Miscellaneous O&M	26,234	14.32%	40.08	5.74
7	TOTAL	183,188	100.00%		19.86

FOOTNOTE 3: CALCULATION OF GST LEAD TIME ON OM&A					
GST CATEGORY		Amounts for the 12 months ended 8/31/06 ($000s)	Weighting Factor	GST Expense Lead Time	Weighted Expense Lead Time
		(A)	(B)	(C)	(D)
1	Consulting and contract staff	2,586	8.9%	44.64	3.96
2	Lease Payments	357	1.2%	46.68	0.57
3	Miscellaneous O&M	26,234	89.9%	47.16	42.40
	TOTAL	**29,177**	**100.0%**		**46.93**

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6		
1	**Components**	**Inputs**	**2009 Historical**	**2010 Board-Approved**	**2010 Bridge**	**2011 Test**		Note:
2	Quantities	Total Purchased Energy kWh	25,223,333,205	25,755,312,099	25,374,336,844	25,285,555,387	(a)	
3		System Network kW	45,866,852	47,042,108	45,743,535	45,354,351	(b)	
4		Line Connection kW	45,260,814	46,349,983	44,204,502	44,762,681	(c)	
5		Transformer Connection kW	46,183,386	47,615,738	45,914,712	45,888,120	(d)	
6		Own Use kWh	15,313,085	20,459,541	17,819,269	18,577,820	(e)	
7	Prices	HOEP (incl GA) ($/kWh)	0.0623	0.0630	0.0644	0.0725	(f)	
8		Network Rate ($/kW)	2.65	2.57	2.98	3.21	(g)	
9		Line Connection Rate ($/kW)	0.70	0.70	0.75	0.79	(h)	
10		Transformer Connection Rate ($/kW)	1.57	1.62	1.73	1.85	(i)	
11		Wholesale Market Services Rate ($/kWh)	0.0049	0.0046	0.0045	0.0047	(j)	
12		Rural Rate Protection Charge ($/kWh)	0.0012	0.0013	0.0013	0.0013	(k)	
13	Other	Switch Gear Credit ($)	(7,769,870)	(10,200,000)	(8,169,997)	(8,496,792)	(l)	
14		H1 Low Voltage ($)	197,385	180,000	192,027	196,800	(m)	
15		Agincourt Shortfall Load Transfer ($)	423,956	423,956	316,500	316,500	(n)	
16		Hydro One MSP costs ($)	833,133	780,000	901,700	855,600	(o)	
17								
18		Energy	1,572.4	1,622.6	1,635.1	1,833.7	(a) * (f)	For further description of the HOEP rate
19		Transmission - Network	121.4	120.9	136.2	145.6	(b) * (g)	used please see response to BOMA I48
20		Transmission - Connection	31.8	32.4	33.0	35.4	(c) * (h)	
21		Transmission - Transformer Connection	72.5	77.1	79.3	84.9	(d) * (i)	
22		Rural Rate Protection Charge	30.2	33.5	33.0	32.9	(a) * (k)	
23		Wholesale Market Services	124.2	118.5	113.0	118.4	(a) * (j)	
24		Switch Gear Credit	(7.8)	(10.2)	(8.2)	(8.5)	(l)	
25		H1 Low Voltage ($)	0.2	0.2	0.2	0.2	(m)	
26		Agincourt Shortfall Load Transfer ($)	0.4	0.4	0.3	0.3	(n)	
27		Hydro One MSP costs ($)	0.8	0.8	0.9	0.9	(o)	
28		THESL Own Use Deduction (18,577,820 kWh)	(1.1)	(1.3)	(1.4)	(1.5)		
29		**Total Cost of Power (calculated)**	**1,945.0**	**1,994.9**	**2,021.5**	**2,242.1**		

Working Capital Allowance	2009 Historical		2010 Approved		2010 Bridge		2011 Test	
	Values	Values @ Working Capital Factors	Values	Values @ Working Capital Factors	Values	Values @ Working Capital Factors	Values	Values @ Working Capital Factors
- Cost of Power @ 10.63%	1,946,811,402	206,946,052	1,994,736,710	212,040,512	2,021,517,468	214,887,307	2,242,116,161	238,336,948
- EXPENSES								
- OM&A Expense @ 14.12%	189,684,716	26,783,482	202,073,347	28,532,757	208,796,704	29,482,095	226,817,269	32,026,598
- Interest on Long term debt @ 7.73%	64,014,563	4,948,326	71,596,043	5,534,374	68,794,850	5,317,842	73,998,450	5,720,080
- Income, and Capital Tax @ 9.18%	27,018,501	2,480,298	27,018,501	2,480,298	27,018,501	2,480,298	28,139,191	2,583,178
- Debt Retirement Charge (@ 10.47%	174,057,257	18,223,795	174,057,257	18,223,795	174,057,257	18,223,795	170,887,949	17,891,968
- HST (See HST Calculations Below)		7,426,632		6,767,518		7,002,800		21,833,217
		266,808,585		**273,579,254**		**277,394,137**		**318,391,990**

GST Calculations	**2009 Historical Forecast Year Amounts (Mil $s) (A)**	**5% GST (B) = (A) * 5%**	**Net Lead (lag) Days (C)**	**GST Benefit (Cost) (D) = (B) * (C)**	**2010 Approved Forecast Year Amounts (Mil $s) (A)**	**5% GST (B) = (A) * 5%**	**Net Lead (lag) Days (C)**	**GST Benefit (Cost) (D) = (B) * (C)**
Revenue @ -18.49 Days	2,137,695,156	106,884,758	(18.49)	(5,415,869)	2,542,227,233	127,111,362	(18.49)	(6,440,754)
Cost of power @ 43.58 Days	1,946,811,402	97,340,570	43.58	11,623,086	1,994,736,710	99,736,835	43.58	11,909,216
OM&A Expenses @ 46.93 Days	189,684,716	9,484,236	46.93	1,219,414	202,073,347	10,103,667	46.93	1,299,056
TOTAL				**7,426,632**				**6,767,518**

GST Calculations	**2010 Bridge Forecast Year Amounts (Mil $s) (A)**	**5% GST (B) = (A) * 5%**	**Net Lead (lag) Days (C)**	**GST Benefit (Cost) (D) = (B) * (C)**	**2011 Test Forecast Year Amounts (Mil $s) (A)**	**13% HST (B) = (A) * 13%**	**Net Lead (lag) Days (C)**	**GST Benefit (Cost) (D) = (B) * (C)**
Revenue @ -18.49 Days	2,529,529,148	126,476,457	(18.49)	(6,408,584)	2,544,647,085	330,804,121	(18.49)	(16,761,901)
Cost of power @ 43.58 Days	2,021,517,468	101,075,873	43.58	12,069,105	2,242,116,161	291,475,101	43.58	34,803,990
OM&A Expenses @ 46.93 Days	208,796,704	10,439,835	46.93	1,342,279	226,817,269	29,486,245	46.93	3,791,128
TOTAL				**7,002,800**				**21,833,217**

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INTERROGATORY 80:

Reference(s): **D1/T7/S1/p.16**
D1/T8/S10/p.5

In the first of these references, THESL's "Total Capital" for the 2011 Test year is shown as $498.0 million.

In the second of these references, the "Total Capital Plan" amount for 2011 is shown as $396.6 million.

Please provide an explanation for the differences between these two numbers and if any revisions are necessary, please provide them.

RESPONSE:

The $396.6 million in the "2011-2020 Electrical Distribution Capital Plan" (Exhibit D1, Tab 8, Schedule 10) captures plans directly associated with Distribution Systems. The $498.0 million in "Summary of Capital Budget" (Exhibit D1, Tab 7, Schedule 1) includes plans on Distribution Systems as well as other items such as: General Plant, Customer Services, Information Technologies and Energy Storage proposed expenditures.

Every item in the 2011-2020 Electrical Distribution Capital Plan can be found in the Summary of Capital Budget. No revisions are necessary.

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INTERROGATORY 81:

Reference(s): **D1/ T9/ S6**
D1/ T8/ S10

In the first reference THESL provides details on Station System Enhancement and table 1 shows a total capital expenditure of $33.1 million for the 2011 test year.

On page 5, line 15 of the second reference, Stations System Enhancement, THESL shows projected total costs of $48.1 million in 2011. Please explain the difference and, if necessary, provide any evidence updates. Please state whether or not the Bremner TS station is the only project in this category for the 2011 test year. If it is not, please state what other projects are included and their respective amounts.

RESPONSE:

The Stations System Enhancement projected total costs of $48.1 million in 2011 on page 5, line 15 of Exhibit D1, Tab 8, Schedule 10 consists of the Bremner TS capital expenditure of $33.1 million and capital contributions to HONI of $15 million for a number of other Stations Enhancement projects. The projects and the respective capital contributions to HONI can be found in Table 1 of Exhibit D2, Tab 1, Schedule 1.

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INTERROGATORY 82:

Reference(s): **E1/ T1/ S1/p.3**
E1/Tab 3/Sch 2/p.1

The first reference states that:

"THESL's debt is issued at the THC level, as it is the parent who is rated by the credit rating agencies. The utility is assigned debt through promissory notes between the utility and the parent. The promissory notes are written on the same terms as the parent debt as the borrowing is done on behalf of the corporation's affiliates. A fee of five basis points is charged for administration."

Table 1 of Exh E1/Tab 3/Sch 2/p.1 outlines THESL's medium and long-term debt costs for 2010. Included is the $980 million City Note maturing May 6, 2013 with a principal amount of $490,115,467.

a) Please confirm that this debt was restructured by the City of Toronto in March 2010 and sold to debt capital market participants.
b) Please provide a copy of the related short form prospectus.
c) Please state whether or not THC was required to consent to the restructuring.
d) Please state whether or not THC was required to waive any terms of the Promissory Notes, and if so, please state what waivers were provided.
e) Please state whether THC received any consideration for facilitating this transaction. If so, please specify the amount and highlight where in the application it is reflected. If such consideration was not received, please state why not.

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f) Please confirm that the City of Toronto realized a gross gain on the restructuring and sale transaction of approximately $38.79 million, or if THESL does not believe this to be the case, please explain.

g) Please state whether THC, at any time, contemplated the early retirement of the Promissory Notes held by the City for the benefit of ratepayers. If not, please state why not.

h) Please explain whether the proposed dollar cost of Long-Term Debt is appropriate after having regard to this restructuring and sale transaction.

i) Please state whether or not, given this transaction, the approach outlined in the above reference, wherein THESL's promissory notes are written on the same terms as the parent debt, was followed in actual practice and in spirit and, if not, why not.

j) Given the transfer of corporate services from THC to THESL that has taken place in recent years, as outlined in Exh C1/Tab 2/Sch 1, including the treasury function, please state why it is still necessary for THESL to be charged the five basis point fee for administration referenced above.

RESPONSES:

a) Confirmed. The remaining City-held debt was sold by the City of Toronto to debt capital market participants on March 25, 2010, with the transactions settling on April 1, 2010.

b) A copy of the related short form prospectus is attached as Appendix A to this Schedule.

c) THC consent was not required. Section 3.1 of the City Note contemplated the City's ability to convert its City Note into other instruments issued or offered by THC "in an

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equivalent principal amount…" THC co-operated with the City to qualify the distribution of the new notes by filing a prospectus but THC consent was not required.

d) THC was not required to waive any terms of the Promissory Notes.

e) In order to get the best pricing terms, the City determined to distribute the debentures issued upon conversion of the City Note (in accordance with its terms) through a public distribution or sale process led by a syndicate of underwriters (in what is referred to as a secondary offering). In order to do so, the debentures had to be qualified for sale to the public under a short form prospectus of THC prepared and filed in accordance with applicable securities laws. The City reimbursed THC for these and related costs. THC received absolutely no consideration for facilitating this transaction.

f) The City of Toronto sold its THC Notes at a price that resulted in a net present value of $530.3 million, which was $40.2 million higher than the par value of the notes. Out of this amount, the City paid underwriters fees of $1.4 million, for a net present value after fees of $38.79 million. It is also important to note that, in selling the notes prior to maturity, the City gave up $74 million in interest payments from THC on these notes.

g) THC did not contemplate the early retirement of the Promissory Notes held by the City as the economics of an early retirement did not favour such an action

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h) The proposed dollar cost of Long-Term Debt is appropriate because there is no change in the coupon rate that is being paid on the restructured notes. It is important to understand that the sale of the City-held notes did not change the underlying structure of the notes; the City simply sold the notes at prevailing market prices. The only difference is that THC's obligations on the notes shifted to institutional holders from the City.

i) As noted in part h) above, because there is no change to the underlying structure of the debentures issued by THC there is no change to structure of the Promissory Notes at THESL. THESL submits that all of the promissory notes are written on the same terms as the parent debt, in spirit and in actual practice.

j) There are certain activities at the THC level which do not lend themselves to an intercompany fee, and for which THC finds it appropriate to continue charging a 5 basis point administrative fee. Such activities include preparing and delivering road show presentations (in anticipation of and prior to debt issues) by the President and CEO and CFO, presentations and briefings given to senior management of credit rating agencies (outside of the regular annual updates by the rating agencies), and one-on-one presentations to investment bankers and institutional investors by the President and CEO and CFO.

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Information has been incorporated by reference in this prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Investment Relations Officer of Toronto Hydro Corporation, 14 Carlton Street, Toronto, Ontario, M5B 1K5, (416) 542-2707 and are also available electronically at www.sedar.com.*

The securities to be issued hereunder have not been and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold within the United States or to United States persons. See "Plan of Distribution".

SHORT FORM PROSPECTUS

Secondary Offering March 25, 2010

toronto hydro corporation

TORONTO HYDRO CORPORATION

$245,057,000 6.11% Senior Unsecured Debentures due 2011
$245,057,000 6.11% Senior Unsecured Debentures due 2013

This short form prospectus qualifies the distribution (the "Offering") by the City of Toronto of $245,057,000 aggregate principal amount of 6.11% Senior Unsecured Debentures due 2011 (the "2011 Debentures") and $245,057,000 aggregate principal amount of 6.11% Senior Unsecured Debentures due 2013 (the "2013 Debentures" and, together with the 2011 Debentures, the "Debentures") of Toronto Hydro Corporation (the "Corporation"). The Debentures are being offered pursuant to an underwriting agreement dated March 25, 2010 (the "Underwriting Agreement") between the City of Toronto, the Corporation and RBC Dominion Securities Inc., CIBC World Markets Inc. and Scotia Capital Inc. (collectively, the "Underwriters"). The determination of the terms of the Offering and the offering price for the Debentures offered hereunder were made through negotiations between the City of Toronto and the Underwriters. The Debentures will be issued under a trust indenture dated May 7, 2003 (as supplemented by a fourth supplemental indenture in the case of the 2011 Debentures and a fifth supplemental indenture in the case of the 2013 Debentures to be dated, in each case, on or about the closing date of the Offering) between the Corporation and CIBC Mellon Trust Company, as trustee (collectively, the "Indenture").

The sole shareholder of the Corporation is the City of Toronto. The Corporation currently has approximately $490.1 million of indebtedness outstanding to the City of Toronto under the terms of an amended and restated promissory note dated May 1, 2006 (the "City Note"). Concurrent with the closing of the Offering, the City Note will be converted, in accordance with its terms, into the Debentures which will be offered for sale by the Underwriters in accordance with the terms of the Underwriting Agreement and issued under the Indenture. The Corporation will not receive any proceeds from the Offering. Following the completion of the Offering, the Corporation will have no further indebtedness outstanding to the City of Toronto under the terms of the City Note and the City of Toronto will continue to be the sole shareholder of the Corporation. See "Relationship with the City of Toronto Following Completion of the Offering" and "Plan of Distribution".

The Debentures are not obligations of, and are not guaranteed in any manner by, the City of Toronto.

	Price to Public[(1)(2)]	Underwriters' Fee	Net Proceeds to the City of Toronto[(3)]
Per $1,000 principal amount of 2011 Debentures	$1,068.66 (106.866%)	$2.00 (0.20%)	$1,066.66 (106.666%)
Total	$261,882,614 (106.866%)	$490,114 (0.20%)	$261,392,500 (106.666%)
Per $1,000 principal amount of 2013 Debentures	$1,095.38 (109.538%)	$3.75 (0.375%)	$1,091.63 (109.163%)
Total	$268,430,536 (109.538%)	$918,963 (0.375%)	$267,511,573 (109.163%)

(1) **Based on the price to public and the interest rate for the 2011 Debentures to be sold under this Offering, the effective yield to maturity is 2.09% per annum.**

(2) **Based on the price to public and the interest rate for the 2013 Debentures to be sold under this Offering, the effective yield to maturity is 2.87% per annum.**

(3) Before deducting expenses of the Offering, estimated to be $500,000, which together with the Underwriters' fee, will be paid by the City of Toronto. The Corporation will not receive any proceeds from the Offering.

(cover continued on following page)

There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this prospectus. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. See "Risk Factors".

The Underwriters have agreed, as principals, to conditionally offer the Debentures, subject to prior sale, if, as and when sold and delivered by the City of Toronto and the Corporation and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by McMillan LLP, on behalf of the City of Toronto by Cassels Brock & Blackwell LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP.

Subscriptions for the Debentures will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will occur on or about April 1, 2010, or on such later date as may be agreed upon, but in any event not later than April 8, 2010. A global Debenture representing each of the 2011 Debentures and the 2013 Debentures will be issued in registered form only to CDS Clearing and Depository Services Inc. ("CDS"), or its nominee, and will be deposited with CDS on the closing date of this Offering. A purchaser of the Debentures will receive only a customer confirmation of purchase from the registered dealer who is a CDS participant and from or through whom the Debentures are purchased.

Subject to applicable laws, the Underwriters may, in conjunction with the Offering, effect transactions which stabilize or maintain the market price of the Debentures at levels other than those which might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Unless otherwise specified, all references to currency in this short form prospectus are to Canadian dollars.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

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SUMMARY OF THE OFFERING

The information set forth below is a summary of certain of the material attributes and characteristics of the Debentures offered hereby which does not purport to be complete and is qualified in its entirety by the more detailed information contained elsewhere in this prospectus and by reference to the Indenture.

Debentures Offered:	$245,057,000 aggregate principal amount of 6.11% Senior Unsecured Debentures due 2011 (the "2011 Debentures"). $245,057,000 aggregate principal amount of 6.11% Senior Unsecured Debentures due 2013 (the "2013 Debentures").
Price:	$1,068.66 (per $1,000 principal amount of 2011 Debentures). $1,095.38 (per $1,000 principal amount of 2013 Debentures).
Interest:	The 2011 Debentures will bear interest at a fixed annual rate of 6.11%, payable in equal semi-annual instalments on June 30 and December 30 in each year and on the maturity date. The aggregate initial interest payment, payable on June 30, 2010 in respect of the 2011 Debentures, will be $3,691,968.34 (representing $15.06575342 per $1,000 principal amount of 2011 Debentures). The 2013 Debentures will bear interest at a fixed annual rate of 6.11%, payable in equal semi-annual instalments on May 6 and November 6 in each year and on the maturity date. The aggregate initial interest payment, payable on May 6, 2010 in respect of the 2013 Debentures, will be $1,435,765.46 (representing $5.85890411 per $1,000 principal amount of 2013 Debentures).
Currency:	Canadian dollars.
Issue Date:	The Debentures will be dated April 1, 2010.
Delivery Date:	April 1, 2010.
Maturity Date:	The 2011 Debentures will mature on December 30, 2011. The 2013 Debentures will mature on May 6, 2013.
Specified Denominations:	$1,000 and integral multiples thereof.
ISIN / CUSIP:	2011 Debentures – CA 891190AB68 / 891190AB6. 2013 Debentures – CA 891190AC42 / 891190AC4.
Rank:	The Debentures will be direct unsecured obligations of the Corporation and will rank equally (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation, including indebtedness of the Corporation outstanding under a $500 million revolving credit facility with a syndicate of Canadian banks and debentures of every other series issued pursuant to the Indenture.
Redemption of 2013 Debentures at the Option of the Corporation:	The 2013 Debentures may be redeemed at the Corporation's option, in whole at any time or in part from time to time, prior to maturity, on not more than 60 and not less than 15 business days prior notice, at a price equal to the greater of the Canadian Yield Price and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" is an amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the 2013 Debentures, using as a discount rate the sum of the Canada Yield and 13 basis points, calculated at 10:00 a.m. (Toronto time) three business days prior to the redemption date of the 2013 Debentures.

	"Canada Yield" on any date is the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada Bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the 2013 Debentures.
Purchase for Cancellation:	The Corporation may, at any time and from time to time, purchase Debentures for cancellation, in the open market, by tender or private contract, at any price.
Covenants:	The Debentures will have the benefit of certain covenants which, subject to certain exceptions, will restrict the ability of the Corporation and its designated subsidiaries to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets. For a more detailed description of these covenants, see "Description of the Debentures – Covenants".
Governing Law:	The Debentures and the Indenture will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.
Ratings:	The Debentures have been assigned a rating of "A(high)" with a stable trend by DBRS Limited and a rating of "A" by Standard & Poor's. See "Ratings".
Market for the Debentures:	There is no market through which the Debentures may be sold and purchasers may not be able to resell the Debentures purchased hereunder. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. See "Risk Factors".

DOCUMENTS INCORPORATED BY REFERENCE

The following documents of the Corporation filed with the provincial securities regulatory authorities in Canada are incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder:

(a) the annual information form (the "AIF") of the Corporation dated March 8, 2010 (including management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2009); and

(b) the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2009 and December 31, 2008.

All material change reports (excluding confidential material change reports), unaudited interim consolidated financial statements of the Corporation (and management's discussion and analysis relating thereto) and any business acquisition report filed by the Corporation with the securities regulatory authorities in Canada after the date of this prospectus and prior to the termination of the Offering will be deemed to be incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder.

Any statement contained in this prospectus or in a document incorporated or deemed to be incorporated by reference herein will be deemed to be modified or superseded, for purposes of this prospectus, to the extent that a statement contained herein or in any subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded will not constitute a part of this prospectus, except as so modified or superseded.

FORWARD-LOOKING INFORMATION

Certain information included or incorporated by reference in this prospectus constitutes "forward-looking information". The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information. The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information, including, without limitation, the following factors: the timing and amount of future cash flows generated by the Corporation's investments, market liquidity and the quality of the underlying assets and financial instruments; the timing and extent of changes in prevailing interest rates; inflation levels; legislative, judicial and regulatory developments that could affect revenues or the business carried on by Toronto Hydro; LDC's ability to continue to maintain and operate the distribution system reliably and safely in the future; LDC's ability to develop, maintain and manage a complex information technology systems infrastructure; the volume of electricity consumed by LDC's customers; credit risk with respect to customer non-payment; the Corporation's ability to arrange sufficient and cost-effective debt financing; Toronto Hydro's ability to attract and retain the required workforce; the effects of natural and other unexpected occurrences; Toronto Hydro's ability to obtain or maintain adequate insurance to cover all losses or liabilities that might arise at rates it considers reasonable; Toronto Hydro's compliance with Canadian federal, provincial and municipal environmental regulation (changes in environmental regulation or enforcement may impose material additional costs on Toronto Hydro); material changes in Toronto Hydro's assessment of the estimated fair value of its investments; a credit rating change; Toronto Hydro's ability to develop plans and approaches that are acceptable to its labour unions; the risks associated with being controlled by the City of Toronto as well as potential conflicts of interest that may arise between Toronto Hydro, the City of Toronto and related parties; Toronto Hydro's ability to obtain formal access agreements with respect to certain terminal stations and municipal substations located on lands owned by the Province of Ontario, the City of Toronto and others; and more than one distribution licence could be issued for the same area and there is a possibility that in the future some business functions or activities could be separated from LDC and made open to more competition from non-regulated business entities, or that defined geographical areas within LDC's service area may be electrically supplied by a means other than through LDC's system. All of the forward-looking information included or incorporated by reference in this prospectus is qualified by these cautionary statements and those made in the "Risk Factors" section of this prospectus, those made in the "Risk Factors" section of the AIF and those made in the "Risk Factors" section of the Corporation's management's discussion and analysis of financial condition and results of operation for the year ended December 31, 2009 which is included in the AIF. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein or in the documents incorporated by reference. The Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Capitalized terms used in this section without definition, have the meanings given to them elsewhere in this prospectus.

ELIGIBILITY FOR INVESTMENT

In the opinion of McMillan LLP and Blake, Cassels & Graydon LLP, the Debentures offered hereby, if issued on the date of this prospectus, would be, on such date, a qualified investment under the *Income Tax Act* (Canada) (the "Tax Act") for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan, a registered disability savings plan, a tax-free savings account or a deferred profit sharing plan, other than a deferred profit sharing plan for which the Corporation, or a person or partnership with which the Corporation does not deal at arm's length, is the employer. The Debentures will not be a "prohibited investment" for a tax-free savings account where the holder of the tax-free savings account is not a "specified shareholder" of the Corporation, within the meaning of the Tax Act, and the Corporation deals at arm's length with the holder and any person or partnership in which the holder has a "significant interest", within the meaning of the Tax Act.

TORONTO HYDRO

Toronto Hydro Corporation (the "Corporation" and, together with its subsidiaries, "Toronto Hydro") is a holding company which, through its wholly-owned subsidiaries:

- *Toronto Hydro-Electric System Limited* ("LDC") - distributes electricity and engages in conservation and demand management activities; and

- *Toronto Hydro Energy Services Inc.* - provides street lighting services.

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system which delivers electricity to approximately 690,000 customers located in the City of Toronto. LDC is the largest municipal electricity distribution company in Canada. The business of LDC is regulated by the Ontario Energy Board which has broad powers relating to licensing and standards of conduct and service and the regulation of rates charged by LDC and other electricity distributors.

The sole shareholder of the Corporation is the City of Toronto. Council of the City of Toronto has adopted a shareholder direction (the "Shareholder Direction") which sets out certain governance principles with respect to Toronto Hydro. The Shareholder Direction and certain services provided by Toronto Hydro to the City of Toronto are described in the AIF under "Relationship with the City of Toronto".

RELATIONSHIP WITH THE CITY OF TORONTO FOLLOWING COMPLETION OF THE OFFERING

The Corporation currently has approximately $490.1 million of indebtedness outstanding to the City of Toronto under the terms of the City Note. Under the terms of the City Note, the Corporation is required to repay the principal amount of the City Note in two equal instalments on December 30, 2011 and May 6, 2013. Interest is payable under the terms of the City Note at a fixed annual rate of 6.11%. A copy of the City Note is attached to a material change report of the Corporation dated September 5, 2006 available at www.sedar.com.

The City of Toronto has determined to monetize its interest in the City Note. Concurrent with the closing of the Offering, the City Note will be converted, in accordance with its terms, into the Debentures which will be offered for sale by the Underwriters in accordance with the terms of the Underwriting Agreement and issued under the Indenture. The determination of the terms of the Offering and the offering price for the Debentures offered hereunder were made through negotiations between the City of Toronto and the Underwriters. The Corporation will not receive any proceeds from the Offering.

Following the completion of the Offering, the Corporation will have no further indebtedness outstanding to the City of Toronto under the terms of the City Note and the City of Toronto will continue to be the sole shareholder of the Corporation and the Shareholder Direction will remain in effect.

See "Plan of Distribution".

DESCRIPTION OF THE DEBENTURES

The Debentures will be issued under a trust indenture dated May 7, 2003 (as supplemented by a fourth supplemental indenture in the case of the 2011 Debentures and a fifth supplemental indenture in the case of the 2013 Debentures to be dated, in each case, on or about the closing date of the Offering) between the Corporation and CIBC Mellon Trust Company (the "Trustee") (collectively, the "Indenture").

The following is a summary of the material attributes of the Debentures. This summary does not purport to be complete. For a complete description of the Debentures, reference should be made to the Indenture. Certain capitalized terms used in this summary are defined below under "Definitions".

Maturity and Interest Rate

The 2011 Debentures will mature on December 30, 2011 and will bear interest at a fixed annual rate of 6.11%, payable in equal semi-annual instalments on June 30 and December 30 in each year and on the maturity date. The aggregate initial interest payment, payable on June 30, 2010 in respect of the 2011 Debentures, will be $3,691,968.34 (representing $15.06575342 per $1,000 principal amount of 2011 Debentures).

The 2013 Debentures will mature on May 6, 2013 and will bear interest at a fixed annual rate of 6.11%, payable in equal semi-annual instalments on May 6 and November 6 in each year and on the maturity date. The aggregate initial interest payment, payable on May 6, 2010 in respect of the 2013 Debentures, will be $1,435,765.46 (representing $5.85890411 per $1,000 principal amount of 2013 Debentures).

Rank

The Debentures will be direct unsecured obligations of the Corporation and will rank equally (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation, including indebtedness of the Corporation under a $500 million revolving credit facility with a syndicate of Canadian banks (the "THC Revolving Credit Facility") and debentures of every other series issued pursuant to the Indenture.

The Debentures are not obligations of, and are not guaranteed in any manner by, the City of Toronto.

Redemption of 2013 Debentures

The 2013 Debentures may be redeemed at the Corporation's option, in whole at any time or in part from time to time, prior to maturity, on not more than 60 and not less than 15 business days prior notice, at a price equal to the greater of the Canadian Yield Price and par, together with accrued and unpaid interest to the date fixed for redemption.

"Canada Yield Price" is an amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the 2013 Debentures, using as a discount rate the sum of the Canada Yield and 13 basis points, calculated at 10:00 a.m. (Toronto time) three business days prior to the redemption date of the 2013 Debentures.

"Canada Yield" on any date is the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada Bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the 2013 Debentures.

If less than all the 2013 Debentures are to be redeemed, the 2013 Debentures so redeemed will be selected by the Trustee on a pro rata basis or by lot or such other means as the Trustee may deem equitable and expedient.

Purchase for Cancellation

The Corporation may, at any time, purchase Debentures for cancellation, in the open market, by tender or by private contract, at any price.

Covenants

Negative Pledge

The Corporation will not, and will not permit any Designated Subsidiary to, create, assume or suffer to exist any Security Interest, other than Permitted Encumbrances, on or over any of its assets (present or future) to secure any Obligation, unless at the same time it shall secure equally and rateably therewith all the debentures issued pursuant to the Indenture then outstanding.

Limitation on Funded Indebtedness

The Corporation will not, and will not permit any Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Funded Indebtedness unless, after giving effect thereto, Consolidated Funded Indebtedness would not exceed 75% of Total Consolidated Capitalization. This covenant will not operate to prevent the Corporation or a Designated Subsidiary from issuing, incurring, assuming or otherwise becoming liable for or in respect of any Inter-Company Indebtedness and Non-Speculative Financial Instrument Obligations. This covenant will operate to prevent the Corporation or a Designated Subsidiary from assigning any Inter-Company Indebtedness to a person other than the Corporation or a Designated Subsidiary.

Limitation on Designated Subsidiary Indebtedness

The Corporation will not permit a Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Indebtedness except:

(a) Inter-Company Indebtedness of the Designated Subsidiary;

(b) Non-Recourse Debt of the Designated Subsidiary;

(c) Non-Speculative Financial Instrument Obligations of the Designated Subsidiary;

(d) Permitted Capital Lease Obligations of the Designated Subsidiary;

(e) Prudential and Bilateral Credit Support Obligations of the Designated Subsidiary;

(f) Purchase Money Obligations of the Designated Subsidiary; and

(g) any other Indebtedness of the Designated Subsidiary (in addition to the Indebtedness referred to in paragraphs (a) to (f)) if, after giving effect to the Indebtedness, the aggregate amount of all Indebtedness of all Designated Subsidiaries permitted by this paragraph (g) only would not exceed 5% of Consolidated Net Worth.

For the purposes of this covenant, the assignment by the Corporation to a third party of Inter-Company Indebtedness owing by a Designated Subsidiary will be considered to be an incurrence of Indebtedness by such Designated Subsidiary.

Designation of Subsidiaries as Designated Subsidiaries

LDC is a Designated Subsidiary. The board of directors of the Corporation may designate a subsidiary of the Corporation in addition to LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the designation, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the designation, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) none of the shares of the subsidiary is owned by another subsidiary of the Corporation that is not a Designated Subsidiary.

The board of directors of the Corporation may terminate the designation of a subsidiary of the Corporation other than LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the termination, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the termination, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) the subsidiary does not own any Funded Indebtedness of the Corporation or any shares or Funded Indebtedness of any other Designated Subsidiary.

Restriction on Mergers and Dispositions

The Corporation will not, directly or indirectly through a Designated Subsidiary, enter into a transaction or series of transactions in which all or substantially all of the undertaking, property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or otherwise, unless:

(a) the person is a corporation organized and existing under the laws of Canada or a province or territory thereof and expressly assumes, by a supplemental indenture satisfactory in form to the Trustee and its counsel and executed and delivered to the Trustee, all of the covenants and obligations of the Corporation under the Indenture and all debentures issued pursuant to the Indenture; and

(b) at the time of and after giving effect to the reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or other transaction, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing.

Events of Default

The following are Events of Default applicable to all series of debentures, including the Debentures, issued pursuant to the Indenture:

(a) failure to pay principal or premium (if any) on the debentures when due;

(b) failure to pay interest on the debentures when due if such failure continues for a period of 30 days;

(c) the sale, transfer, lease or other disposition of all or substantially all of the property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis other than in accordance with the covenants described above under " - Covenants - Restriction on Mergers and Dispositions";

(d) failure to observe or perform any other covenant or condition contained in the Indenture if such failure continues for a period of 60 days after written notice thereof has been given to the Corporation by the Trustee or the holders of at least 25% in principal amount of the debentures of any affected series then outstanding;

(e) failure by the Corporation or any Material Subsidiary to pay principal, premium (if any) or interest due on any Indebtedness, the principal amount of which is more than $50 million in the aggregate, beyond the applicable grace period;

(f) failure by the Corporation or any Material Subsidiary to observe or perform any provision of any agreement under which Indebtedness is created if such failure has the effect of causing more than $50 million of such Indebtedness in the aggregate to become due and payable or to be required to be redeemed or repurchased before its stated maturity;

(g) the rendering by a court of competent jurisdiction of one or more judgments against the Corporation or any Material Subsidiary in an aggregate amount of more than $50 million if the judgments remain undischarged or unstayed for more than 30 days; and

(h) specified events of bankruptcy, insolvency or reorganization affecting the Corporation or any Material Subsidiary.

Default

If an Event of Default described in paragraphs (a) to (g) above occurs and is continuing, the Trustee or the holders of not less than 25% of the principal amount of debentures of a series of debentures issued pursuant to the Indenture then outstanding may declare the principal amount of, and the premium (if any) and accrued and unpaid interest on all debentures of that series then outstanding to be due and payable immediately.

If an Event of Default described in paragraph (h) above occurs and is continuing, the principal amount of and the premium (if any) and accrued and unpaid interest on all debentures issued pursuant to the Indenture then outstanding shall be due and payable immediately without any declaration or other action by the Trustee or the holders of the debentures.

Protection of Trustee

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an event of default applicable to a series of debentures issued pursuant to the Indenture occurs and is continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any holders of such debentures unless the Trustee is sufficiently indemnified in accordance with the provisions of the Indenture. Subject to the provisions of the Indenture providing for the indemnification of the Trustee, the holders of the requisite principal amount of such debentures will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any rights or powers of the Trustee in respect of such debentures.

Modification

The Indenture provides that certain rights, privileges, restrictions and conditions of debentures issued and outstanding under the Indenture may be modified if such modifications are authorized by extraordinary resolution.

The term "extraordinary resolution" is defined in the Indenture to mean:

(a) in the case of modifications which affect a particular series of debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding; and

(b) in the case of modifications which affect all debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of all debentures then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of all debentures then outstanding, treated in each case as a single class.

Defeasance

The Indenture requires the Trustee to release the Corporation from its obligations in respect of a series of debentures issued pursuant to the Indenture if specified conditions are met, including the deposit by the Corporation of cash or certain cash-equivalent securities for the payment of all principal and interest and any other amounts on the debentures of such series and the payment of the expenses of the Trustee.

Form, Transfer and Payment Mechanics

The Debentures will be issued in denominations of $1,000 and integral multiples thereof. Each of the 2011 Debentures and the 2013 Debentures will be represented by one or more global Debentures (collectively, the "Global Debenture") registered in the name of CDS Clearing and Depository Services Inc. or a successor thereof (the "Depository") or its nominee and held by or on behalf of the Depository as custodian for institutions (including the Underwriters) which participate directly or indirectly in the Depository's book-entry only registration system ("BEO Participants"). Interests in the Debentures represented by the Global Debenture will be evidenced by credits to book-entry accounts of BEO Participants maintained with the Depository. Interests of the owners of Debentures represented by the Global Debenture will be evidenced by credits to accounts maintained with such BEO Participants on behalf of such owners.

Purchasers of Debentures represented by the Global Debenture will not be entitled to certificates or other instruments from the Corporation or the Depository evidencing their ownership of Debentures. Beneficial owners of Debentures represented by the Global Debenture will not be shown on the registers maintained by the Trustee or the records maintained by the Depository but will be shown through book-entry accounts of BEO Participants. The rights of beneficial owners of Debentures represented by the Global Debenture may be exercised only through the BEO Participants with which such book-entry accounts are maintained. Purchasers of Debentures represented by the Global Debenture will receive a customer confirmation of purchase from the registered dealer who is a BEO Participant and from or through whom the Debentures are purchased.

Purchasers of Debentures represented by the Global Debenture will receive definitive Debentures registered in their name only:

(a) if the Corporation determines that the Depository is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global Debenture in connection with the Debentures and the Corporation is unable to locate a qualified successor;

(b) if the Corporation elects to terminate the book-entry only registration of Debentures through the Depository; or

(c) in certain other specified circumstances.

Transfers of interests in Debentures represented by the Global Debenture will be effected through records maintained by the Depository or its nominee (with respect to interests of BEO Participants) and on the records of BEO Participants (with respect to interests of persons other than BEO Participants). Beneficial owners of Debentures represented by the Global Debenture who are not BEO Participants but who desire to transfer any interest in Debentures may do so only through BEO Participants.

Payments of interest and principal on the Global Debenture will be made to the Depository or its nominee as registered holder of the Global Debenture. As long as the Depository or its nominee is the registered owner of the Global Debenture, the Depository or its nominee will be considered the sole owner of the Global Debenture for the purposes of receiving payment on the Global Debenture and for all other purposes under the Indenture and the Global Debenture.

The Corporation expects that the Depository or its nominee, upon receipt of any payment of principal or interest in respect of the Global Debenture, will credit the accounts of BEO Participants, on the date principal or interest is payable, with payments in amounts proportionate to their respective interests in the principal amount of the Global Debenture as shown on the records of the Depository or its nominee. The Corporation also expects that payments of principal and interest by BEO Participants to the owners of interests in the Debentures represented by the Global Debenture held through accounts maintained with BEO Participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of BEO Participants. The responsibility and liability of the Corporation and the Trustee in respect of Debentures represented by the Global Debenture is limited to making payment of any principal and interest due on the Global Debenture to the Depository or its nominee.

Governing Law

The Indenture is and the Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

Definitions

The following defined terms used in this section of the prospectus are defined in the Indenture substantially as set out below.

"Capital Lease" means, with respect to a person, a lease or other arrangement in respect of real or personal property that is required to be classified and accounted for as a capital lease on a balance sheet of the person in accordance with accounting principles generally accepted in Canada.

"Capital Lease Obligation" means, with respect to a person, the obligation of the person to pay rent or other amounts under a Capital Lease.

"Consolidated Funded Indebtedness" means the aggregate amount of all Funded Indebtedness of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with accounting principles generally accepted in Canada.

"Consolidated Net Worth" means the shareholder's equity of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with accounting principles generally accepted in Canada. For greater certainty, the shareholder's equity of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determination.

“Contingent Liability” means, with respect to a person, any agreement, undertaking or arrangement by which the person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the obligation, debt or other liability of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any Contingent Liability will, subject to any limitation contained therein, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the obligation, debt or other liability to which the Contingent Liability relates.

“Deferred Purchase Price Obligation” means, with respect to a person, an obligation issued, incurred or assumed by the person in connection with the acquisition by the person of an asset in respect of the deferred purchase price of the asset.

“Designated Subsidiary” means Toronto Hydro-Electric System Limited and, until such designation is terminated in accordance with the covenants described above under “ - Covenants - Designation of Subsidiaries as Designated Subsidiaries”, any other subsidiary of the Corporation designated as a Designated Subsidiary by the board of directors of the Corporation in accordance with the covenants described above under “ - Covenants - Designation of Subsidiaries as Designated Subsidiaries”.

“Event of Default” means an event of default under the Indenture.

“Financial Instrument Obligations” means, with respect to any person, obligations arising under:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time; and

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity;

or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing, in each case to the extent of the net amount due or accruing due by the person under the obligations determined by marking the obligations to market in accordance with their terms.

“Funded Indebtedness” means Indebtedness (other than Subordinated Indebtedness) that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) greater than 18 months.

“Indebtedness” means, with respect to a person, without duplication:

(a) all obligations of the person for borrowed money, including obligations with respect to bankers’ acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments;

(b) all Financial Instrument Obligations of the person;

(c) all Deferred Purchase Price Obligations of the person;

(d) all Capital Lease Obligations and Purchase Money Obligations of the person;

(e) all Prudential and Bilateral Credit Support Obligations of the person; and

(f) all Contingent Liabilities of the person with respect to obligations of another person if such obligations are of the type referred to in paragraphs (a) to (e).

"Inter-Company Indebtedness" means, with respect to the Corporation, indebtedness of the Corporation to a Designated Subsidiary and, with respect to a Designated Subsidiary, indebtedness of the Designated Subsidiary to the Corporation or to another Designated Subsidiary.

"Material Subsidiary" means a Designated Subsidiary and any other subsidiary of the Corporation:

(a) the total assets of which represent more than 10% of the total assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with accounting principles generally accepted in Canada; or

(b) the total revenues of which represent more than 10% of the total revenues of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with accounting principles generally accepted in Canada.

For greater certainty, the assets and revenues of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determinations.

"Non-Recourse Debt" means, with respect to a person, any indebtedness incurred to finance the creation, development, construction or acquisition of an asset of the person (and any extensions, renewals or refunding of any such indebtedness) provided that the recourse of the obligee thereof against the person is limited in all circumstances (other than in respect of false or misleading representations or warranties) to the asset (including all rights and benefits related to or arising out of the asset).

"Non-Speculative Financial Instrument Obligations" means, with respect to a person, Financial Instrument Obligations of the person entered into by the person in the ordinary course of business for risk management purposes and not for speculative or capital raising purposes.

"Obligations" means, with respect to a person, without duplication, all items which, in accordance with accounting principles generally accepted in Canada, would be included as liabilities on the liability side of the balance sheet of the person and all Contingent Liabilities of the person.

"Permitted Capital Lease Obligations" means, with respect to a Designated Subsidiary, the obligation of the Designated Subsidiary to pay rent or other amounts under a Capital Lease, other than a Capital Lease entered into as part of a Sale and Leaseback Transaction unless:

(a) the property which is the subject matter of the Sale and Leaseback Transaction is owned by the Designated Subsidiary;

(b) the proceeds of sale of such property have been determined by the board of directors of the Designated Subsidiary to be at least equal to its fair value; and

(c) either of the following is applicable:

(1) at the time of the Sale and Leaseback Transaction, the cost of acquiring such property could have been financed pursuant to a Purchase Money Obligation; or

(2) within 120 days after completion of the Sale and Leaseback Transaction, the Designated Subsidiary reduces its Indebtedness, other than Indebtedness permitted pursuant to paragraphs (a) to (e) above under " - Covenants - Limitation on Designated Subsidiary Indebtedness", by an amount at least equal to the net proceeds from the Sale and Leaseback Transaction.

"Permitted Encumbrances" means:

(a) any Security Interest securing Obligations of a Designated Subsidiary that:

(1) exists before and at the time that the Designated Subsidiary becomes a Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the Designated Subsidiary becoming a Designated Subsidiary; and

(3) immediately before and after the Designated Subsidiary becomes a Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(b) any Purchase Money Mortgage or Capital Lease of the Corporation or a Designated Subsidiary;

(c) any Security Interest in an asset created or assumed by the Corporation or a Designated Subsidiary to secure Non-Recourse Debt of the Corporation or the Designated Subsidiary in respect of such asset;

(d) any Security Interest in cash, marketable debt securities or accounts receivable created or assumed by the Corporation or a Designated Subsidiary to or in favour of a bank or other lending institution to secure indebtedness of the Corporation or the Designated Subsidiary that is payable on demand or that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) of 18 months or less and that is incurred by the Corporation or the Designated Subsidiary in the ordinary course of business and for the purpose of carrying on the same;

(e) any Security Interest in cash or marketable debt securities created or assumed by the Corporation to secure Non-Speculative Financial Instrument Obligations of the Corporation if the aggregate value of such cash and marketable debt securities is not more than 105% of the aggregate amount of the Non-Speculative Financial Instrument Obligations;

(f) any Security Interest created or assumed by a Designated Subsidiary in favour of the Corporation or any Wholly-Owned Designated Subsidiary;

(g) any Security Interest in an asset acquired by the Corporation or a Designated Subsidiary that secures Obligations of any other person, whether or not such Obligations are assumed by the Corporation or the Designated Subsidiary provided that the Security Interest:

(1) exists before and at the time that the asset is acquired by the Corporation or the Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the asset being acquired by the Corporation or the Designated Subsidiary; and

(3) immediately before and after the asset is acquired by the Corporation or the Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(h) any Security Interest in cash or marketable debt securities in a sinking fund account established by the Corporation in support of a series of debentures issued pursuant to the Indenture;

(i) any Security Interest or deposit under workers' compensation, social security or similar legislation or in connection with bids, tenders, leases, contracts or expropriation proceedings or to secure public or statutory obligations, surety and appeal bonds or costs of litigation where required by law;

(j) any Security Interest or privilege imposed by law, such as builders', mechanics, material men's, carriers', warehousemen's and landlords' liens and privileges; or any Security Interest or privilege arising out of judgments or awards with respect to which the Corporation or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending such appeal or proceedings for review; or any Security Interest for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Corporation or a Designated Subsidiary in good faith; or any undetermined or inchoate Security Interest or privilege incidental to current operations that has not been filed pursuant to law against the Corporation or a Designated Subsidiary or that relates to obligations not due or delinquent; or the deposit of cash or securities in connection with any Security Interest or privilege referred to in this paragraph (j);

(k) any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, licence, franchise, grant or permit held or acquired by the Corporation or a Designated Subsidiary, or by any statutory provision, to terminate the lease, licence, franchise, grant or permit or to purchase assets used in connection therewith or to require annual or other periodic payments as a condition of the continuance thereof;

(l) any Security Interest or right of distress reserved in or exercisable under any lease for rent to which the Corporation or a Designated Subsidiary is a party and for compliance with the terms of the lease;

(m) any Security Interest created or assumed by the Corporation or a Designated Subsidiary in favour of a public utility or any municipality or governmental or other public authority when required by the utility, municipality or other authority in connection with the operations of the Corporation or a Designated Subsidiary;

(n) any reservations, limitations, provisos and conditions expressed in original grants from the Crown;

(o) any minor encumbrances, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions applicable to the Corporation's or a Designated Subsidiary's use of real property, that do not in the aggregate materially detract from the value of the property or materially impair its use in the operation of the business of the Corporation or the Designated Subsidiary;

(p) any extension, renewal, alteration, substitution or replacement, in whole or in part, of a Security Interest referred to in paragraphs (a) to (o) provided that the Security Interest is limited to all or part of the same assets, the principal amount of the secured Obligations is not increased by that action, the term of the secured Obligations is not shortened and the terms and conditions of the Security Interest are no more restrictive in any material respect than the Security Interest so extended; and

(q) any other Security Interest created or assumed by the Corporation or a Designated Subsidiary (in addition to the Security Interests referred to in paragraphs (a) to (p)) if, after giving effect to the Security Interest, the aggregate amount of all Indebtedness secured by Security Interests permitted by this paragraph only does not at that time exceed 5% of Consolidated Net Worth.

"Prudential and Bilateral Credit Support Obligations" means, without duplication, the following obligations:

(a) all contingent reimbursement obligations of the Corporation relating to letters of credit and other financial instruments and all Contingent Liabilities of the Corporation in respect of Obligations of a subsidiary of the Corporation for the purchase or sale of electricity or natural gas; and

(b) all obligations of a Designated Subsidiary for borrowed money, including contingent reimbursement obligations relating to letters of credit and other financial instruments under credit facilities established for participants in the wholesale market for electricity administered by the Independent Electricity System Operator ("IESO"), in respect of the Obligations of the Designated Subsidiary for the purchase or sale of electricity or natural gas;

if such obligations were incurred or assumed to satisfy:

(x) prescribed prudential requirements in the wholesale market for electricity administered by the IESO;

(y) credit support arrangements required by electricity distribution companies under the terms of the Retail Settlement Code established by the Ontario Energy Board; or

(z) credit support requirements of counterparties under bilateral contracts or customers under purchase contracts.

"Purchase Money Mortgage" means, with respect to a person, any Security Interest created or assumed by the person to secure a Purchase Money Obligation provided that such Security Interest is limited to the asset financed by such Purchase Money Obligation and is created or assumed not later than three months after such Purchase Money Obligation is issued, incurred or assumed.

"Purchase Money Obligation" means, with respect to a person, indebtedness of the person issued, incurred or assumed to finance all or part of the cost of acquiring any asset for the person, other than shares, bonds and other securities, or constructing, installing or improving any real property or fixtures of the person, provided that the indebtedness is issued, incurred or assumed within twelve months after such acquisition, construction, installation or improvement, and includes any extension, renewal or refunding of such indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased.

"Sale and Leaseback Transaction" means, with respect to a person, a transaction or series of transactions pursuant to which the person sells or transfers real or personal property owned by the person to a third party and subsequently leases such real or personal property.

"Security Interest" means any security interest, assignment by way of security, mortgage, charge (whether fixed or floating), hypothec, pledge, lien or other encumbrance on or interest in property or assets that secures the payment of Obligations.

"Subordinated Indebtedness" means all indebtedness of the Corporation in respect of which, upon any distribution of assets of the Corporation upon any dissolution, winding-up, liquidation or reorganization of the Corporation (whether in bankruptcy, insolvency or receivership proceedings or upon an assignment for the benefit of creditors, or any other marshalling of the assets and liabilities of the Corporation or otherwise), the payment of all indebtedness and liabilities of the Corporation in connection with all debentures issued pursuant to the Indenture including principal, interest, fees and expenses, must be satisfied in full prior to any amount being applied to such indebtedness.

"Total Consolidated Capitalization" means, without duplication, the sum of:

(a) the principal amount of all Consolidated Funded Indebtedness;

(b) the principal amount of all Subordinated Indebtedness; and

(c) the Consolidated Net Worth;

in each case, as determined by the Corporation and its Designated Subsidiaries.

"Wholly-Owned Designated Subsidiary" means a Designated Subsidiary all of the outstanding shares in the capital of which are owned by the Corporation or one or more Wholly-Owned Designated Subsidiaries.

USE OF PROCEEDS

The Corporation will not receive any proceeds from the Offering. Following the completion of the Offering, the Corporation will have no further indebtedness outstanding to the City of Toronto under the terms of the City Note.

The net proceeds to the City of Toronto from the sale of the Debentures will be approximately $528,404,073 after deducting the Underwriters' fee and the expenses of the Offering which will each be paid by the City of Toronto.

CONSOLIDATED CAPITALIZATION

The following table sets out the consolidated capitalization of the Corporation as at December 31, 2009 both before and after giving effect to the Offering.

	Outstanding as at December 31, 2009	**Outstanding as at December 31, 2009 after giving effect to the Offering**
	(in thousands of dollars)	
Long-term debt		
Senior unsecured debentures		
6.11% due May 7, 2013	$ 225,000	$ 225,000
5.15% due November 14, 2017	250,000	250,000
4.49% due November 12, 2019	250,000	250,000
2011 Debentures	–	245,057
2013 Debentures	–	245,057
City Note	490,115	–
Total long-term debt	$1,215,115	$1,215,115(1)
Shareholder's equity		
Common shares	$ 567,817	$ 567,817
Retained earnings	430,437	430,437
Total shareholder's equity	998,254	998,254
Total capitalization	$2,213,369	$2,213,369

Note:

(1) Does not add due to rounding.

RATINGS

The Debentures have been assigned a rating of "A(high)" with a stable trend by DBRS Limited ("DBRS") and a rating of "A" by Standard & Poor's ("S&P").

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". A DBRS rating may be modified by the addition of "high" or "low" to indicate relative standing within the major rating categories. The "A" category is characterized as "satisfactory credit quality". The "A" category is considered to be more susceptible to adverse economic conditions and has greater cyclical tendencies than higher-rated securities; however, protection of interest and principal is still substantial. An A rating is the second of the three sub-categories within the third of the ten rating categories. S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". An S&P rating may be modified by the addition of a plus or minus sign to indicate relative standing within the major rating categories. The "A" category is characterized as somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong. An A rating is the second of the three sub-categories within the third of the ten rating categories.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

EARNINGS COVERAGE

The following table sets forth the earnings coverage ratio for the Corporation derived from the Corporation's audited consolidated annual financial statements for the twelve-month period ended December 31, 2009 after giving effect to the Offering:

	December 31, 2009
Earnings coverage on long-term debt obligations(1)	1.85 times

(1) The earnings coverage ratio on long-term debt (including any current portion) is equal to earnings (before interest and "payments in lieu" of corporate income taxes) divided by interest expense on long-term debt (including any current portion). Interest expense excludes any amounts in respect of amortization that were included in interest expense as shown in the consolidated statement of earnings of the Corporation for the period.

The Corporation's interest requirements on long-term debt, after giving effect to the Offering, amounted to $73.1 million for the twelve-month period ended December 31, 2009. The Corporation's earnings before interest expense and "payments in lieu" of corporate income taxes for the twelve-month period ended December 31, 2009 was $134.9 million, which is 1.85 times the Corporation's interest requirements on long-term debt for such period.

PLAN OF DISTRIBUTION

Pursuant to the Underwriting Agreement dated March 25, 2010 between the City of Toronto, the Corporation and the Underwriters:

(a) the City of Toronto has agreed to sell and assign $490,114,000 aggregate principal amount of the City Note to the Underwriters for an aggregate purchase price of $530,313,150;

(b) the Underwriters will convert the City Note, in accordance with its terms, into the Debentures which will be offered for sale by the Underwriters in accordance with the terms of the Underwriting Agreement and issued under the Indenture; and

(c) the remaining principal amount outstanding under the City Note ($1,477.50) will be purchased for cancellation by the Corporation.

In consideration for their services in connection with the Offering, the City of Toronto has agreed to pay the Underwriters an aggregate fee of $1,409,077 ($2.00 per $1,000 principal amount of 2011 Debentures and $3.75 per $1,000 principal amount of 2013 Debentures).

The determination of the terms of the Offering and the offering price for the Debentures offered hereunder were made through negotiations between the City of Toronto and the Underwriters. The Corporation will not receive any proceeds from the Offering. Following the completion of the Offering, the Corporation will have no further indebtedness outstanding to the City of Toronto under the terms of the City Note.

The obligations of the Underwriters under the Underwriting Agreement are several, and not joint, and may be terminated at their discretion upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Debentures if any are purchased under the Underwriting Agreement. If an Underwriter fails to purchase the Debentures which it has agreed to purchase, any one or more of the other Underwriters may, but is not obligated to, purchase such Debentures.

The Corporation has agreed to indemnify the Underwriters against certain liabilities, including liabilities under applicable Canadian securities legislation, or to contribute to payments the Underwriters may be required to make in respect of those liabilities. The Corporation has also agreed to indemnify the City of Toronto against certain liabilities, including liabilities under applicable securities legislation or to contribute to payments the City of Toronto may be required to make in respect of those liabilities.

The Underwriters may not, throughout the period of distribution, bid for or purchase the Debentures. The foregoing restriction is subject to certain exceptions, on the condition that the bid or purchase not be engaged in for the purpose of creating actual or apparent active trading in, or raising the price of the Debentures. These exceptions include a bid or purchase permitted under the Universal Market Integrity Rules of the Investment Industry Regulatory Organization of Canada relating to market stabilization and passive market-making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution. The Corporation has been advised by the

Underwriters that, in connection with the Offering and subject to the foregoing, the Underwriters may effect transactions which stabilize or maintain the market price of the Debentures at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Debentures have not and will not be registered under the United States *Securities Act of 1933*, as amended (the "U.S. Securities Act"), or any state securities laws, and may not be offered or sold within the United States or to U.S. persons (as defined in the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable state securities laws or an exemption therefrom is available. Each of the Underwriters will agree not to buy or offer to buy, to sell or offer to sell, or solicit any offer to buy any Debentures in the United States, or to or for the account or benefit of U.S. persons, except to "qualified institutional buyers" in accordance with Rule 144A under the U.S. Securities Act. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Debentures in the United States. In addition, until 40 days after the commencement of the Offering, an offer or sale of the Debentures within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the U.S. Securities Act.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of McMillan LLP, counsel to the Corporation, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, the following is, at the date hereof, a summary of the principal Canadian federal income tax considerations generally applicable to a holder of the Debentures (a "Holder") who acquires Debentures pursuant to the Offering and who, at all relevant times, for purposes of the Tax Act, is resident in Canada, holds the Debentures as capital property and deals at arm's length and is not affiliated with the Corporation. Generally, the Debentures will be considered capital property to a Holder provided that the Holder does not hold the Debentures in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Holders who are resident in Canada whose Debentures might not otherwise qualify as capital property may be entitled to obtain such qualification in certain circumstances by making an irrevocable election permitted by subsection 39(4) of the Tax Act.

This summary is not applicable to a Holder that is a "financial institution" for the purposes of the mark-to-market rules in the Tax Act, a Holder an interest in which is a "tax shelter investment" for the purposes of the Tax Act, or a Holder that has elected to report its "Canadian tax results" in a "functional currency" in accordance with the Tax Act. Such Holders should consult their own tax advisors having regard to their particular circumstances.

This summary is based on the current provisions of the Tax Act and the regulations thereunder in force at the date of this prospectus, all specific proposals to amend the Tax Act and the regulations thereunder publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof and counsel's understanding of the administrative policies and assessment practices of the Canada Revenue Agency (the "CRA") published by the CRA prior to the date hereof. There can be no assurance that the proposed amendments will be implemented in their current form or at all. This summary does not otherwise take into account or anticipate any changes of law or practice, whether by judicial, governmental or legislative decision or action or changes in the administrative policies or assessment practices of the CRA, nor does it take into account tax legislation or considerations of any province, territory or foreign jurisdiction. The provisions of provincial income tax legislation vary from province to province in Canada and in some cases differ from federal income tax legislation.

This summary is of a general nature only and is not intended to be, nor should it be construed as, legal or tax advice to any particular Holder, and no representations with respect to the income tax consequences to any particular Holder are made. Accordingly, prospective purchasers should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring, holding and disposing of the Debentures, including the application and effect of the income and other tax laws of any country, province, territory, state or local tax authority.

Taxation of Interest

A Holder that is a corporation, partnership, unit trust or trust of which a corporation or partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on a Debenture that accrues or is deemed to accrue to the Holder to the end of that taxation year or becomes receivable or is received by the Holder before the end of that taxation year, except to the extent that such interest was otherwise included in the Holder's income for a preceding taxation year.

Any other Holder, including an individual and a trust of which neither a corporation nor a partnership is a beneficiary, will be required to include in income for a taxation year any amount on account of, in lieu of payment of or in satisfaction of, interest on a Debenture received or receivable by such Holder in that year (depending upon the method regularly followed by the Holder in computing income), except to the extent that the interest was included in the Holder's income for a preceding taxation year.

Any premium paid by the Corporation to a Holder because of the exercise by the Corporation of the right to redeem a Debenture before the maturity thereof will generally be deemed to be interest received at that time by the Holder to the extent that such premium can reasonably be considered to relate to, and does not exceed at the time of the redemption the value of, the interest that would have been paid or payable by the Corporation on the Debentures for a taxation year ending after the redemption.

Disposition of Debentures

On a disposition or deemed disposition of a Debenture, including on maturity, redemption, purchase for cancellation of the Debenture or otherwise, a Holder will generally be required to include in computing its income for the taxation year in which the disposition occurred an amount equal to the interest accrued or deemed to accrue on the Debenture from the date of the last interest payment to the date of disposition to the extent that such amount has not otherwise been included in the Holder's income for the taxation year or a previous taxation year.

In general, a disposition or deemed disposition of a Debenture will give rise to a capital gain (or capital loss) to the extent that the proceeds of disposition, net of any accrued interest and any other amount included in computing income as interest and any reasonable costs of disposition, exceed (or are less than) the adjusted cost base of the Debenture to the Holder immediately before the disposition. For this purpose, a Holder's adjusted cost base of a Debenture will generally be equal to the average acquisition cost of all Debentures held by the Holder.

One-half of the amount of any capital gain (a "taxable capital gain") realized by a Holder in a taxation year generally must be included in the Holder's income for that year, and one-half of the amount of any capital loss (an "allowable capital loss") realized by a Holder in a taxation year must generally be deducted from taxable capital gains realized by the Holder in that year. Allowable capital losses in excess of taxable capital gains may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years to the extent and under the circumstances described in the Tax Act. Allowable capital losses can generally not be deducted from a Holder's ordinary income. Accordingly, a Holder that realizes a capital loss on a disposition or deemed disposition of a Debenture will not generally be permitted to deduct the loss from the interest on the Debenture included in the Holder's income in the year in which the disposition or deemed disposition occurs or in any preceding year.

The adjusted cost base to a Holder of Debentures acquired pursuant to this Offering will include the amount by which the Holder's acquisition price of the Debentures exceeds their principal amount. Accordingly, on the repayment of Debentures on their maturity date, a Holder will generally realize a capital loss. The Holder will not be permitted to deduct this capital loss from interest on the Debentures included in the Holder's income in the year or in any preceding year.

Capital gains realized by an individual or a trust (other than certain specified trusts) may give rise to a liability for alternative minimum tax under the Tax Act.

A Holder that is a "Canadian controlled private corporation" (as defined in the Tax Act) may be liable to pay an additional refundable tax of 6⅔% on certain investment income, including amounts of interest and taxable capital gains.

RISK FACTORS

In addition to the risks described in the Corporation's AIF under "Risk Factors" and "Annex C (Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors)", prospective purchasers should consider the risks described below before purchasing Debentures.

Rank of Debentures and Holding Company Structure

The Debentures will be direct unsecured obligations of the Corporation and will rank equally with all other unsecured and unsubordinated indebtedness of the Corporation, including indebtedness of the Corporation under the THC Revolving Credit Facility and debentures of every other series issued pursuant to the Indenture. A default by the Corporation under the Indenture will constitute an event of default under the THC Revolving Credit Facility. There can be no assurance that sufficient funds would be available at the time of any such default to make any required payment under the Debentures.

The Corporation is a holding company and substantially all of its business activities are carried on by its subsidiaries. Because the Corporation is a holding company, the Debentures will be effectively subordinated to all existing and future liabilities, including trade payables and other indebtedness, of the Corporation's subsidiaries. In addition, as a holding company, the Corporation's ability to meet its financial obligations is dependent primarily upon the receipt of interest and principal, management fees, cash dividends and other payments from its subsidiaries, together with proceeds raised by the Corporation through the issuance of debt. The Corporation is wholly-owned by the City of Toronto and does not currently raise funds through the issuance of share capital. The Corporation's subsidiaries are distinct legal entities and have no legal obligation, contingent or otherwise, to pay any amount due under the Debentures or to make any amounts available therefor. In addition, the payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions, will depend on the earnings of the subsidiaries and will be subject to various business and other considerations.

Absence of Public Market for the Debentures

There is no existing trading market for the Debentures. The Corporation does not intend to list the Debentures on any Canadian, U.S. or other securities exchange. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. There can be no assurance that a secondary market will develop for the Debentures or that any secondary market that does develop will continue. Accordingly, purchasers may not be able to sell the Debentures. In addition, if a trading market develops for the Debentures, the Debentures could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, the Corporation's results of operations and financial position, the ratings assigned to the Debentures and the Corporation's other debt securities and the markets for similar debt securities.

Ratings

The value of the Debentures will be affected by the general creditworthiness of the Corporation. There is no assurance that any rating assigned to the Debentures issued hereunder will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the relevant rating agency. A lowering or withdrawal of such rating may have an adverse effect on the market value of the Debentures.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Debentures. Generally, the market price or value of the Debentures will decline as prevailing interest rates for comparable debt instruments rise and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the Corporation which may adversely affect its creditworthiness.

Additional Debt Financing

The Corporation expects to borrow to repay the Debentures when required to do so under the terms of the Debentures and to finance the renewal of LDC's electricity infrastructure. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities and general economic conditions.

Shareholder Direction

The Shareholder Direction is not for the benefit of, or enforceable by, the holders of the Debentures.

LEGAL MATTERS

Certain legal matters relating to the Offering will be passed on for the Corporation by McMillan LLP, for the City of Toronto by Cassels Brock & Blackwell LLP and for the Underwriters by Blake, Cassels & Graydon LLP. The partners and associates of each of McMillan LLP, Cassels Brock & Blackwell LLP and Blake, Cassels & Graydon LLP beneficially own, directly or indirectly, less than one per cent of the securities of the Corporation or any associate or affiliate of the Corporation.

AUDITORS

The Corporation's auditors are Ernst & Young LLP, Chartered Accountants. Ernst & Young LLP is independent in Ontario in accordance with its rules of professional conduct.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some provinces, revisions of the price or damages if the prospectus and any amendment contain a misrepresentation or are not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

AUDITORS' CONSENT

We have read the short form prospectus [the "Prospectus"] of Toronto Hydro Corporation [the "Corporation"] dated March 25, 2010 relating to the issuance and distribution of an aggregate principal amount of $245,057,000 6.11% Senior Unsecured Debentures due 2011 and $245,057,000 6.11% Senior Unsecured Debentures due 2013 of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the Prospectus of our report to the shareholder of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2009 and 2008, and the consolidated statements of income, retained earnings and cash flows of each of the years in the two-year period ended December 31, 2009. Our report is dated February 26, 2010 [except as to note 30[d], which is as of March 5, 2010].

(Signed) Ernst & Young LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada
March 25, 2010

CERTIFICATE OF THE CORPORATION

Dated: March 25, 2010

This short form prospectus, together with the documents incorporated by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of all the provinces of Canada.

(Signed) ANTHONY HAINES President and Chief Executive Officer	(Signed) JEAN-SEBASTIEN COUILLARD Chief Financial Officer

On behalf of the Board of Directors

(Signed) CLARE R. COPELAND Director	(Signed) BRIAN CHU Director

CERTIFICATE OF THE UNDERWRITERS

Dated: March 25, 2010

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of all the provinces of Canada.

RBC DOMINION SECURITIES INC.	CIBC WORLD MARKETS INC.	SCOTIA CAPITAL INC.
(Signed) ROBERT M. BROWN	(Signed) CLIFF INSKIP	(Signed) M.W. NEAL

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 83:

Reference(s): **J1/T1/S2, p.4**

Re: Account 1592, it is stated that THESL wishes to clear a $3.3 million credit to customers. With respect to this proposal:

a) Please revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all the relevant information for transaction, adjustments, etc. for all the relevant years.

b) Please describe each type of tax item that has been accounted for in account 1592.

c) Please provide the calculations that show how each item was determined and provide any pertinent supporting evidence.

d) Did the Applicant follow the guidance provided in FAQ July 2007? If not, please explain why not.

e) Please identify the account balance as of December 31, 2009 as per the 2009 audited financial statements. Please identify the account balance as of December 31, 2009 as per the April 2010 2.1.7 RRR filing to the Board. Please provide a reconciliation if the balances provided in the above are not identical to each other and to the total amount shown on the continuity schedule.

f) Please complete the following table based on the previous answers. Add rows as required to complete the analysis in an informative manner, or if THESL considers that any of the rows are not applicable, please delete and provide an explanation. If THESL uses Excel to prepare the table, please submit the live Excel workbook.

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Tax Item	$ Principal As of [December 31, 2009]
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax from 2005 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4 /12ths of approved grossed-up proxy) if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from any prior application not recorded above.	
Insert description of next item(s)	
Insert description of next item(s) and new rows if needed.	
Total	

RESPONSE:

a) There are no changes to the continuity schedule balances relating to PILs 1592. Since this account is considered to be a GROUP 2 account, the Continuity schedule provides all the needed information with regard to the additions & transfers.

b) Please see response in part (f).

c) Please see response in part (f).

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

d) THESL has followed the guidance provided in FAQ July 2007.

e) The total account balance including cumulative carrying charges was $15.197 million as of December 31, 2009 as reported in Note 8 of the 2009 audited financial statements. This balance was reported to the Board in the April 2010 2.1.7 RRR filing.

f)

Tax Item	$ millions Principal As of [December 31, 2009]
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007 [THESL: Not applicable. The item was cleared previously.]	Not applicable
Large Corporation Tax from 2005 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4 /12ths of approved grossed-up proxy) if not recorded in PILs account 1562 [THESL: Not applicable. The item was recorded in PILs account 1562 as instructed in OEB FAQ July 2007.]	Not applicable
Ontario Capital Tax rate decrease and increase in capital deduction for 2007 [THESL: Not applicable. The item was cleared previously.]	Not applicable
Ontario Capital Tax rate decrease and increase in capital deduction for 2008 [THESL: Not applicable. The item was cleared previously.]	Not applicable
Ontario Capital Tax rate decrease and increase in capital deduction for 2009 [THESL: The variance resulted from the decrease in the Ontario Capital Tax rate for the period January 1 to April 30, 2009. The rate decreased from 0.285% to 0.225%. (see Note 1)]	(0.4)
Ontario Capital Tax rate decrease and increase in capital deduction for 2010 [THESL: Not applicable. THESL has not requested clearance of the 2010 variance.]	Not applicable
Capital Cost Allowance class changes from 2006 EDR application for 2006 [THESL: Not applicable. The item was cleared previously.]	Not applicable

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Tax Item	$ millions Principal As of [December 31, 2009]
Capital Cost Allowance class changes from 2006 EDR application for 2007 [THESL: Not applicable. The item was cleared previously.]	Not applicable
Capital Cost Allowance class changes from 2006 EDR application for 2008 [THESL: Not applicable. This item was cleared previously.]	Not applicable
Capital Cost Allowance class changes from 2006 EDR application for 2009 [THESL: The variance resulted from the change in the Capital Cost Allowance ("CCA") rate for eligible computers and software for the period January 1 to December 31, 2009. A variance resulted from the previously reported CCA Class 45 (45%, subject to half-year rule); and new CCA Class 50 (55%, subject to half-year rule) and new CCA Class 52 (100% with no half-year rule). (See Note 2)]	(1.5)
Capital Cost Allowance class changes from 2006 EDR application for 2010 [THESL: Not applicable. THESL has not requested clearance of the 2010 variance.]	Not applicable
Capital Cost Allowance class changes from any prior application not recorded above.	Not applicable
Income Tax Rate decrease for 2009 [THESL: The variance resulted from the decrease in income tax rate for the period January 1 to December 31, 2009. The rate decreased from 34.5% (2008 Rate Model) and 34% (2009 Rate Model) to 33.0%. (see Note 3)]	(1.4)
Insert description of next item(s) and new rows if needed.	Not applicable
Total	(3.3)

Note 1 – Ontario Capital Tax variance due to the decrease in Ontario Capital Tax rate for 2009

For the period May 1, 2008 to April 30, 2009 per 2008 Rate Model

Net taxable capital per 2008 rate model	$2,080,397,659
Decrease in Ontario capital tax rate (0.285% - 0.225%)	0.06%
Increase in PILs 1592 variance liability (not grossed-up)	$ 1,248,239

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Increase in PILs 1592 variance liability for the period January 1, 2009 to April 30, 2009: $1,248,239 x 4/12 = **$416,080**.

Note 2 – Variance due to change in CCA class for 2009

For the period May 1, 2008 to April 30, 2009 per 2008 Rate Model		
CCA class 45 additions per 2008 rate model		$ 6.789,452
Half-year rule (50%)		50%
Reduced CCA class 45 additions before CCA		$ 3,394,726
CCA on Class 45 additions as calculated in 2008 rate model		
$3,394,726 x 45%		$ 1,527,627
CCA on Class 50 additions based on Class 45 additions per 2008 rate model		
$3,394,726 x 55%		1,867,099
Increase in CCA due to change in CCA class		$ 339,472
2009 statutory tax rate		33.0%
Decrease in income tax before grossed-up		$ 112,026
Gross up factor [1/(1-tax rate)]		1.49254
Decrease in income tax (grossed-up)	**[A]**	$ 167,203
For the period May 1, 2009 to April 30, 2010 per 2009 Rate Model		
CCA on opening UCC balance in 2009 rate model		
($6,789,452 - $1,527,627) x 45%		$ 2,367,821
Recalculated CCA on opening UCC balance in 2009 rate model		
($6,789,452 - $1,867,099) x 55%		2,707,294
Increase in CCA due to change in CCA class		$ 339,473
2009 statutory tax rate		33.0%

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Decrease in income tax before grossed-up		$ 112,026
Gross up factor [1/(1-tax rate)]		1.49254
Decrease in income tax (grossed-up)	**[B]**	$ 167,203
CCA class 45 additions per 2009 rate model		$ 5,664,102
Half-year rule (50%)		50%
Reduced CCA class 45 additions before CCA		$ 2,832,051
CCA on Class 45 additions as calculated in 2009 rate model (45%)		
$2,832,051 x 45%		$ 1.274,423
Recalculated CCA on Class 50/52 additions in 2009 rate model		
Class 50 addition: $5,664,102 x 1/12 x 50% x 55%		$ 129,802
Class 52 addition: $5,664,102 x 11/12 x 100%		5,192,094
CCA due to change in CCA class		$ 5,321,896
Increase in CCA due to change in CCA class		$ 4,047,473
2009 statutory tax rate		33.0%
Decrease in income tax before grossed-up		$ 1,335,666
Gross up factor [1/(1-tax rate)]		1.49254
Decrease in income tax (grossed-up)	**[C]**	$ 1,993,535
Total increase in PILS 1592 variance liability for 2009		
Due to 2008 CCA class 45 additions per 2008 rate model		
[A]: $167,203 x 4/12		$ 55,734
Due to 2009 CCA on UCC opening balance per 2009 rate model		
[B]: $167,203 x 8/12		111,469

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Due to 2009 CCA class 45 additions per 2009 rate model		
[C]: $1,993,535 x 8/12		1,329,023
		$ 1,496,226

Note 3 – Variance due to change in Income Tax Rate for 2009

For the period May 1, 2008 to April 30, 2009 per 2008 Rate Model		
Taxable income per 2008 rate model		$59,769,397
2009 statutory tax rate		33.0%
		$19,723,901
Less: Tax credits per 2008 rate model		200,000
Income tax before grossed-up		$19,523,901
Gross up factor [1/(1-tax rate)]		1.49254
Income tax (grossed-up) – recalculated		$29,140,203
Income tax (grossed-up) – per 2008 rate model		31,176,247
Decrease in Income tax due to change in statutory rate	**[D]**	$ 2,036,044

For the period May 1, 2009 to April 30, 2010 per 2009 Rate Model		
Taxable income per 2009 rate model		$50,403,073
2009 statutory tax rate		33.0%
		$16,633,014
Less: Tax credits per 2009 rate model		200,000
Income tax before grossed-up		$16,433,014
Gross up factor [1/(1-tax rate)]		1.49254
Income tax (grossed-up) – recalculated		$24,526,931
Income tax (grossed-up) – per 2009 rate model		25,662,189
Decrease in Income tax due to change in statutory rate	**[E]**	$ 1,135,258

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Total increase in PILS 1592 variance liability for 2009	
Due to change in 2009 statutory income tax rate	
Per 2008 rate model ~ **[D]:** $2,036,044 x 4/12	$ 678,681
Per 2009 rate model ~ **[E]:** $1,135,258 x 8/12	756,839
	$ 1,435,520

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INTERROGATORY 84:

Reference(s): J1/T1/S2

THESL is requesting disposition of account 1508, sub-account IFRS costs, which include forecasted costs to the end of 2010 and is an unaudited balance. The usual practice for disposing of variance and deferral accounts is to use the most up-to-date audited balances, as supported by audited financial statements, plus forecasted carrying charges on those balances up to the start of the new rate year.

Please state why the Board should deviate from the usual practice of disposing only the audited balances.

RESPONSE:

Disposition of account 1508, sub-account IFRS costs is being sought in 2011 given the significant amount spent on the IFRS transition project to date. This account has been collecting costs, as shown in Appendix A of the exhibit, since 2008. The amounts estimated to the end of 2010 are significant at $7.2 million. Waiting another year to collect these costs only increases the amount of carrying charges on the balance. THESL is prepared to record any differences between the amounts approved for clearance in this case and the final audited costs to the end of 2010 in a variance account for future disposition of the $7.2 million, 76% or $5,420,437 has been audited or reviewed by the Corporation's external auditors. This approach holds both the Company and ratepayers harmless from any forecast variance, and ensures timely recovery of costs incurred to date.

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INTERROGATORY 85:

Reference(s): J1/T1/S2 – Carrying Charges

THESL has used the Board prescribed rates for calculating carrying charges for the period from Q1, 2008 to Q2, 2010, and indicated that it would be prepared to recalculate the carrying charges before rate finalization. The rates for Q3 and Q4 2010 are posted on the Board's website.

Please recalculate the carrying costs using the Board-approved carrying charge rates for Q3 and Q4, 2010, as posted on the Board's website, and recalculate the rate riders.

RESPONSE:

The variance between the approved carrying charges for 2010 Q3 and Q4 (0.89% and 1.2%) and those forecast (0.76% and 1.28%) in evidence is marginal. The impact on the carrying charges for all accounts is below $10K and will not have a significant impact on the calculated rate riders.

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INTERROGATORY 86:

Reference(s): J1/T1/S6 – Continuity Schedule, p.1
J1/T1/S2/Table 2

The total for account 1595 under the columns titled "Closing Principal Balance as of Dec.-31-09 Excl. Dec. 2008 balances" and "Closing Interest as of Dec.-31-09 Excluding Dec. 31, 2008 balances" is a $768,328 credit. However, the December 31, 2009 balance requested for disposition per Table 2 is a $500,000 credit.

Please reconcile these two numbers and state which is the one that is being requested for disposition in this proceeding and why?

RESPONSE:

The balance in this account reflects the difference between amounts approved for Clearance in THESL's 2008 rate filing (EB-2007-0680) and amounts actually Collected from customers through the implemented rate rider.

The amount of $500,000 shown in Table 2 of Exhibit J1, Tab 1, Schedule 2 is the principal-only amount to December 31, 2009 (rounded). The calculated sum of $768,328 from Exhibit J1, Tab 2, Schedule 6 is principal plus interest to December 31, 2009.

THESL is seeking to clear a total of $779,406 from this account, which is the December 31, 2009 principal of $491,772, plus interest to April 30, 2011 of 287,633.

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INTERROGATORY 87:

Reference(s): **J1/T1/S2/p.8**

Regarding the regulatory ratemaking treatment of stranded meter costs, some distributors have transferred the cost of stranded meters from Account 1860, Meters, to "Sub-account Stranded Meter Costs" of Account 1555, while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen, please provide the information under the two scenarios (a. and b.) below, as applicable to THESL.

a) If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, answer the following questions:

i. Please describe the accounting treatment followed by THESL on stranded meter costs for financial accounting and reporting purposes.

ii. Please provide the amount of the pooled residual net book value of the removed from service stranded meters, less any sale proceeds and contributed capital, which were transferred to this sub-account as of December 31, 2009.

iii. Since transferring the removed stranded meter costs to the sub-account, was the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation? If so, please provide the total depreciation expense amount for the period from the time the stranded meters were transferred to the sub-account to December 31, 2009.

iv. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, please provide the total depreciation expense amount that would have been applicable for the period from

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the time the stranded meters were transferred to the sub-account to December 31, 2009.

v. Were carrying charges recorded for the stranded meter cost balances in the sub-account, and if so, please provide the total carrying charges recorded to December 31, 2009.

vi. Please provide the estimated amount of the pooled residual net book value of the removed from service meters, less any sale proceeds and contributed capital, at the time when smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, please provide the actual amount.

vii. Please describe how THESL intends to recover in rates stranded meter costs including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

viii. In the outlined format of the table shown below (after b.), Summary of Stranded Meter Cost, please provide the data to derive the total "Residual Net Book Value" amounts for each year.

b) If the stranded meter costs remained recorded in Account 1860, Meters, please answer the following questions:

i. Please describe the accounting treatment followed by THESL on stranded meter costs for financial accounting and reporting purposes.

ii. Please provide the amount of the pooled residual net book value of removed from service stranded meters, less any sale proceeds and contributed capital as of December 31, 2009.

iii. Was the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation? If so, provide the total

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depreciation expense amount for the period from the time the meters became stranded to December 31, 2009.

iv. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, provide the total depreciation expense amount that would have been applicable for the period from the time the meters because stranded to December 31, 2009.

v. Please provide the estimated amount of the pooled residual net book value of the removed from service meters, less any sale proceeds and contributed capital, at the time when smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, please provide the actual amount.

vi. Please describe how THESL intends to recover in rates stranded meter costs including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

vii. In the outlined format of the table shown below, Summary of Stranded Meter Cost, please provide the data to derive the total “Residual Net Book Value” amounts for each year.

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Table x - Summary the Residual Net Book Value of Stranded Meter Costs

Year	Gross Asset (A)	Accumulated Amortization (B)	Net Asset (C = A-B)	Proceeds on Disposition (D)	Contributed Capital (E)	Residual Net Book Value (F=C-D-E)
2006						
2007						
2008						
2009						
2010 (1)						
Total						

(1) For 2010, please indicate whether the amounts provided are on a forecast or actual basis.

RESPONSE:

THESL recorded stranded meter costs remained in Account 1860, Meters.

i. THESL reported stranded meters as part of PP&E (fixed asset) and amortized over 25 years.
ii. As of December 31, 2009, the net book value of stranded meters was recorded as $25,347,000 per the published 2009 Financial Statements.
iii. THESL continued to record depreciation expenses to reduce the net book value through accumulated depreciation. The total depreciation expense for the period from the time THESL started to track stranded meter costs in 2007 to December 31, 2009 is $31,321,293.
iv. Refer to the response above.
v. Additions in Q4 2010 are not known and are difficult to quantify. If the October 31, 2010 balances continue to the end of the year with no new additions, the net book value as of December 31, 2010 will be $23,013,780.

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vi. Given that stranded meters have been booked to Account 1860, Meters amortized over 25 years, the net book value and associated depreciation have been included in Rate Base as part of THESL revenue requirements. This will continue until the assets are fully amortized.

vii. See Table A below for details.

Table A: Summary of the Residual Net Book Value of Stranded Meter Costs

Year	Gross Asset	Accumulated Depreciation	Net Asset	Proceeds on Disposition	Contributed Capital	Residual Net Book Value
	(A)	(B)	(C=A-B)	(D)	(E)	(F=C-D-E)
2006 (1)	0	0	0	0	0	0
2007	64,097,235	47,207,275	19,889,960	0	0	19,889,960
2008	93,973,448	68,107,443	25,866,005	0	0	25,866,005
2009	103,875,474	78,528,568	25,346,906	0	0	25,346,906
2010 (2)	107,649,460	84,635,680	23,013,780	0	0	23,013,780

Notes:

(1) THESL did not track the NBV for stranded meter cost until March 2007.

(2) For 2010, the amounts provided are on a forecast basis using the October 31, 2010 balance as the base.

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INTERROGATORY 88:

Reference(s): J1/T1/S2/AppA

On this page Account 1508 – HST Variance is discussed.

The PST and GST were harmonized effective July 1, 2010. Historically, unlike the GST, the PST was included as an OM&A expense and was also included in capital expenditures. Due to the harmonization of the PST and GST, regulated utilities may benefit from a reduction in OM&A expenses and capital expenditures on an actual basis.

a) Please state whether or not THESL has adjusted its Test Year revenue requirement to account for reductions to OM&A expense and capital expenditures that THESL may realize due to the implementation of the HST effective July 1, 2010. If yes, please identify separately the amounts for OM&A and capital and provide an explanation of how each of those amounts was derived. If no, please identify the amounts in OM&A expense and capital expenditures for the Test Year that were previously subject to PST and are now subject to HST.

b) The Board's decision on THESL's 2010 application established a deferral account and directed THESL to record the incremental input tax credits it receives on distribution revenue requirement items that were previously subject to PST and which become subject to HST. Tracking of these amounts would continue in the deferral account until the effective date of THESL's next cost of service rate order. Has THESL recorded any HST Input Tax Credits or other HST related items in PILs account 1592? If yes, please describe what has been recorded and provide supporting evidence showing how the tracking was done. If not, please explain why not.

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RESPONSE:

a) THESL's Test Year forecast <u>does</u> reflect the implementation of HST July 1, 2010. The budget was developed by the business units with the knowledge that HST would apply to certain of their costs which were previously subject to PST. The budget was not developed by subtracting an amount from a "PST-based" budget, and therefore, there is no way to identify an amount for OM&A or capital that has been "saved".

b) THESL has been recording amounts into the HST deferral account. The revenue requirement impact of the Tax harmonization has been estimated based on PST that has been historically paid. On this basis an estimate of the "savings" beginning July 1, 2010 has been derived and the related impact to customers has been recorded in the deferral account. These amounts will continue to be recorded until the effective date of THESL's next rate order. THESL will apply to clear these amounts in a future rate hearing.

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INTERROGATORY 89:

Reference(s): J1/T1/S2/AppA

Appendix A provides a breakdown of incremental IFRS costs.

a) Please confirm that the revenue requirement numbers for 2011 are based on CGAAP, and not IFRS accounting principles. If confirmed, please identify the fiscal year which THESL will begin reporting its (audited) actual results on an IFRS basis. If not confirmed, please provide a detailed revenue requirement impact statement comparing CGAAP with IFRS.

b) Please state whether or not THESL has undertaken, or plans to undertake a depreciation study related to IFRS implementation and if the latter when such a study would be undertaken. If the study has been undertaken, please state what the impacts are on the present application.

c) Please provide a detailed breakdown and explanation of each cost item in Appendix A.

RESPONSE:

a) THESL confirms that the revenue requirement numbers for 2011 are based on CGAAP, and not IFRS accounting principles. In light of the one-year optional deferral for rate-regulated entities granted by the AcSB, THESL will begin reporting its (audited) actual results on an IFRS basis effective January 1, 2012 (with comparatives for 2011). However, the details for comparison are not available at this time.

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b) THESL undertook depreciation studies related to the IFRS implementation during the third quarter of 2009. There is no impact on the present application, as THESL is still discussing the appropriate application of the study results with its auditors. However, preliminary analysis shows that the asset useful lives are longer than the mandated useful lives of the OEB.

c) Please see the response to Exhibit R1, Tab 3, Schedule 2.

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INTERROGATORY 90:

Reference(s): L1/T2/S1/p10

a) Please explain the rationale for negative cost entries with respect to the cost of several categories of meters assigned to the Residential class

b) Please confirm that there are 34,568 meters used for the Residential class with a per-meter cost of $550, and explain why the cost for these meters is much larger than the majority of Residential meters. Please include a breakdown of these costs.

RESPONSE:

a) The negative values totalling $4,188 have been removed from the model. The removal of these values marginally changes allocated costs and does not change the cost to revenue ratios for any rate class.

b) The $550 per installed meter is the average cost of three phase types of smart meters. Please see the attached table (Appendix A) for the requested breakdown.

LDC Specific 2

TOTAL LDC Specific 2 - Average Installed Costs	**$**	**550**	**(b) / (a)**

LDC Specific 2 - Residential - Types of Meters and Quantity

1 Phase 3 Wire, 240 V., 200 Ampere or lessForm 2S Self-Contained Collectors	1,700	
1 Phase 3 Wire, 240 V., 400 Ampere or moreForm 2S Transformer-type	108	
1 Phase 2 Wire, 240 V., 400 Ampere or moreForm 3S Transformer-type smart non-smart	2,132	
3 Phase 3 Wire Delta, 200 Ampere or lessForm 5S	3,650	
3 Phase 3 Wire Delta, Form 5S Transformer-type	13	
9,000 meters requiring an adaptor for installation adds 1 hour labour, vehicle and $60 additional material Asbestos backerboard, meter base repairs	9,000	
pilot project meters replaced with current smart AMI installed twice & AMI testing	7,732	
Suite Meter SystemsCarma/Quadlogic	10,233	
TOTAL Number of Meters - LDC Specific 2 - Residential	**34,568**	**(a)**

LDC Specific 2 - Residential - Cost of Three Phase Smart Meters

1 Phase 3 Wire, 240 V., 200 Ampere or lessForm 2S Self-Contained Collectors	$	1,530,000	
1 Phase 3 Wire, 240 V., 400 Ampere or moreForm 2S Transformer-type	$	108,000	
1 Phase 2 Wire, 240 V., 400 Ampere or moreForm 3S Transformer-type smart non-smart	$	2,132,000	
3 Phase 3 Wire Delta, 200 Ampere or lessForm 5S	$	1,825,000	
3 Phase 3 Wire Delta, Form 5S Transformer-type	$	13,000	
9,000 meters requiring an adaptor for installation adds 1 hour labour, vehicle and $60 additional material Asbestos backerboard, meter base repairs	$	4,950,000	
pilot project meters replaced with current smart AMI installed twice & AMI testing	$	3,866,000	
Suite Meter SystemsCarma/Quadlogic	$	4,604,850	
TOTAL Cost - LDC Specific 2 - Residential	**$**	**19,028,850**	**(b)**

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INTERROGATORY 91:

Reference(s): L1/T2/S1/p11 and K1/T4/S1

With respect to the first reference, the number of customers in the Intermediate class is 668, while in Table 1 of the second reference the number of customers is shown as 514. Similarly, for the Large Use class, the respective customer numbers are 102 and 47.

a) Please confirm that these two exhibits should show the same customers numbers, or if not please explain why not.
b) If the response to a) is that the two exhibits should show the same customer numbers, please identify which exhibit is correct and make the required changes to the other exhibit.
c) If the entries to the Cost Allocation model (the first reference) are correct, please also make any necessary changes to the rate design and revenue reconciliation exhibit (E M1/T4 /S1).

RESPONSE:

The first reference is to the number of meter points and costs associated with those meters the second tab represents the number of customers. There are customers with multiple meters which are totalized to represent one customer.

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INTERROGATORY 92:

Reference(s): **L1/T1/S1/p.1**
L1/T2/S1/pp. 22-24

Please ensure that the revenue to cost ratios in Table 1 of the first reference are consistent for all classes with those on page 24 of the second reference – in particular for the "2010 Board-approved" ratios for the General Service 50-999 kW class and the Intermediate 1000-4999 kW classes.

With respect to the second reference, please provide a copy of Worksheet O1 that shows the column for the General Service 50-999 kW class.

RESPONSE:

The ratios in Table 1 of the first reference are not directly comparable to the ratios on page 24 of the second reference.

Table 1 of Exhibit L1, Tab 1, Schedule 1 shows the Board-approved 2010 revenue to cost ratios, and the 2011 proposed ratios. Page 24 of Exhibit L1, Tab 2, Schedule 1 shows the 2011 revenue to cost ratios before they are adjusted to the proposed ratios (note that the title on page 24 indicates "2010", but this is a typo and should read "2011".)

Exhibit L1, Tab 2, Schedule 1 also inadvertently omitted the GS 50-999kW class. A corrected table is attached hereto as Appendix A.

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Toronto Hydro-Electric System Limited

Sheet O1 Revenue to Cost Summary Worksheet - First Run

			1	2	3	5	6	7	9
Rate Base Assets		Total	Residential	GS <50	GS>50<999	GS > 1000 < 4999	Large Use >5MW	Street Light	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$589,908,703	$241,882,573	$76,247,439	$175,539,743	$52,763,859	$25,908,304	$13,490,831	$4,075,953
mi	Miscellaneous Revenue (mi)	$19,737,464	$10,687,162	$4,119,891	$3,768,769	$623,751	$209,159	$178,578	$150,154
	Total Revenue	**$609,646,167**	**$252,569,735**	**$80,367,331**	**$179,308,512**	**$53,387,610**	**$26,117,463**	**$13,669,409**	**$4,226,108**
	Expenses								
di	Distribution Costs (di)	$95,032,620	$38,252,097	$11,761,676	$28,046,186	$9,066,150	$4,493,365	$2,732,674	$680,472
cu	Customer Related Costs (cu)	$48,167,726	$29,471,256	$10,381,200	$6,768,909	$567,537	$88,419	$487,663	$402,740
ad	General and Administration (ad)	$83,098,605	$39,302,936	$12,459,316	$20,301,326	$5,628,414	$2,667,279	$2,086,542	$652,792
dep	Depreciation and Amortization (dep)	$176,517,196	$85,676,968	$22,419,816	$42,677,653	$11,696,746	$5,391,175	$6,965,435	$1,689,402
INPUT	PILs (INPUT)	$27,982,635	$13,239,733	$3,519,916	$6,983,053	$1,978,893	$924,591	$1,075,146	$261,304
INT	Interest	$72,098,034	$34,112,538	$9,069,160	$17,992,031	$5,098,672	$2,382,234	$2,770,143	$673,256
	Total Expenses	**$502,896,816**	**$240,055,528**	**$69,611,084**	**$122,769,159**	**$34,036,412**	**$15,947,063**	**$16,117,604**	**$4,359,967**
	Direct Allocation	**$14,818,523**	**$0**	**$0**	**$3,160,842**	**$5,874,797**	**$5,782,885**	**$0**	**$0**
NI	Allocated Net Income (NI)	$91,930,827	$43,496,246	$11,563,913	$22,941,295	$6,501,219	$3,037,542	$3,532,157	$858,456
	Revenue Requirement (includes NI)	$609,646,167	$283,551,774	$81,174,996	$148,871,295	$46,412,429	$24,767,490	$19,649,760	$5,218,423
		Revenue Requirement Input equals Output							

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Toronto Hydro-Electric System Limited

Sheet O1 Revenue to Cost Summary Worksheet - First Run

	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$4,027,995,924	$1,929,518,436	$510,891,880	$996,064,648	$271,033,885	$124,869,733	$157,447,347	$38,169,995
gp	General Plant - Gross	$606,964,860	$287,216,885	$76,689,688	$152,393,057	$42,124,653	$19,541,699	$23,332,934	$5,665,944
accum dep	Accumulated Depreciation	($2,350,643,775)	($1,135,792,324)	($298,959,327)	($574,925,240)	($154,622,076)	($70,866,094)	($92,966,602)	($22,512,113)
co	Capital Contribution	($278,795,475)	($132,034,668)	($36,221,914)	($72,709,320)	($17,007,753)	($7,471,784)	($10,753,175)	($2,596,860)
	Total Net Plant	$2,005,521,534	$948,908,329	$252,400,327	$500,823,145	$141,528,709	$66,073,554	$77,060,504	$18,726,967
	Directly Allocated Net Fixed Assets	$22,410,269	$0	$0	$784,359	$3,585,643	$18,040,267	$0	$0
COP	Cost of Power (COP)	$2,242,116,161	$453,954,442	$194,745,938	$922,356,804	$421,197,528	$234,714,069	$10,028,518	$5,118,861
	OM&A Expenses	$226,298,951	$107,026,289	$34,602,193	$55,116,422	$15,262,101	$7,249,063	$5,306,879	$1,736,005
	Directly Allocated Expenses	$11,998,159	$0	$0	$3,062,129	$5,423,539	$3,512,492	$0	$0
	Subtotal	*$2,480,413,271*	*$560,980,731*	*$229,348,131*	*$980,535,354*	*$441,883,168*	*$245,475,623*	*$15,335,397*	*$6,854,866*
0.128959325	**Working Capital**	$319,872,422	$72,343,697	$29,576,580	$126,449,178	$56,984,955	$31,656,371	$1,977,642	$883,999
	Total Rate Base	$2,347,804,226	$1,021,252,025	$281,976,907	$628,056,682	$202,099,308	$115,770,192	$79,038,146	$19,610,966
		Rate Base Input equals Output							

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Toronto Hydro-Electric System Limited

Sheet O1 Revenue to Cost Summary Worksheet - First Run

Equity Component of Rate Base	**$939,121,690**	**$408,500,810**	**$112,790,763**	**$251,222,673**	**$80,839,723**	**$46,308,077**	**$31,615,259**	**$7,844,386**
Net Income on Allocated Assets	**$91,930,827**	**$12,514,207**	**$10,756,247**	**$53,378,511**	**$13,476,401**	**$4,387,515**	**($2,448,195)**	**($133,859)**
Net Income on Direct Allocation Assets	**$514,330**	**$0**	**$0**	**$18,002**	**$82,293**	**$414,036**	**$0**	**$0**
Net Income	**$92,445,157**	**$12,514,207**	**$10,756,247**	**$53,396,513**	**$13,558,694**	**$4,801,551**	**($2,448,195)**	**($133,859)**
RATIOS ANALYSIS								
REVENUE TO EXPENSES %	**100.00%**	89.07%	99.01%	120.45%	115.03%	105.45%	69.57%	80.98%
EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($30,982,039)	($807,666)	$30,437,217	$6,975,181	$1,349,973	($5,980,352)	($992,315)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.84%	3.06%	9.54%	21.25%	16.77%	10.37%	-7.74%	-1.71%

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INTERROGATORY 93:

Reference(s): **D1/ T8/ S7/pp.1-2**
M1/T2/S2

On page 1, Table 1: "Metering Capital Investments Summary" shows that in 2011, $12.6 million has been included for smart metering.

On page 2, it is stated that this amount includes $1.2 million to complete the residential installations. Of the remaining cost, $10.8 million is allocated to complete the commercial meter installations. The balance of $0.6 million is to cover the cost of developing two elements of smart meter data collection, expanding Wide Area Network ("WAN") and optimization of Local Area Network ("LAN").

The second reference is THESL's proposed Tariff of Rates and Charges for May 1, 2011. It includes a smart meter rate adder of $0.68.

a) Please state why THESL did not apply in the present application to clear the balances in the smart meter deferral accounts for 2008 and 2009.
b) Please provide THESL's views as to whether or not its proposal to incorporate $12.6 million of smart metering costs into rate base on a prospective basis is in compliance with the Board's Smart Meter Guidelines (G-2008-0002). If THESL believes it is, please explain why. If THESL believes it isn't, please explain why the Board should consider THESL's proposed approach.
c) Please provide a breakdown of the proposed costs. Please confirm that the $12.8 million sought for recovery in the present application relates only to 2011 expenditures and does not include any cost recovery related to prior year expenditures not yet incorporated into rate base.

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d) Please provide a revenue requirement calculation showing prospective smart metering costs including the forecast 2011 expenditure and costs for any subsequent years until the anticipated completion of THESL' smart meter installation program and any proposed offsets by smart meter funding collected through THESL's utility-specific funding adder. Please include an explanation as to why THESL is maintaining the $0.68 funding adder in its proposed 2011 tariff.

e) Please state why in light of THESL's proposal to incorporate 2011 smart meter costs in rate base it also proposes to continue collecting the smart meter funding adder of $0.68.

RESPONSE:

a) Prior to the issuance of the Board's Smart Meter Guidelines (G-2008-0002) referred to in part b) of this interrogatory, THESL had filed for recovery of smart meter account balances and clearance of deferred smart meter assets into ratebase. At page 12 of those Guidelines, the Board states:

> "The Board also expects that only two applications will need to be made for the recovery of smart meter costs. The first is when the distributor achieves at least 50% penetration of smart meters within its service area. The second is when the distributor installs 100% of the meters. The 50% threshold will assist in managing the workload of interested parties and will help ensure that the distributor has sufficient experience with its smart meter activities to enable it to provide detailed cost information."

Since THESL's smart meter rollout program was not complete by the end of 2009, THESL concluded that it would file a separate application to clear the smart meter

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

deferral account balances after audited information became available for 2010, the year when THESL's smart meter rollout program will be complete.

b) THESL's view is that the Smart Meter Guidelines are silent on the issue of costs incurred after completion of the smart meter rollout, and that the treatment of post-rollout costs is properly within the scope of this hearing and the power of this Panel. Thus THESL's proposal is neither compliant nor non-compliant with the Smart Meter Guidelines.

With respect to why the Board should consider THESL's application on this specific matter, THESL takes the view that post-rollout smart meter activities are part of the core business of the utility and do not represent extraordinary undertakings.

c) The $12.6 million (not $12.8 million) for smart meter capital investments consists of $9.5 million in materials, $2.8 million in labour, and $0.3 million in vehicle usage charges. The $12.6 million sought for recovery in the present application relates only to 2011 expenditures and does not include any cost recovery related to prior year expenditures not yet incorporated into rate base.

d) As noted in part (a), THESL's smart meter rollout will be complete in 2010. The 2011 Revenue Requirement associated with costs related to ongoing smart meter activities is approximately $2.9 million. This is made up of $2.4 million in OM&A, $0.2 million depreciation, $0.2 million return on rate base, and approximately $0.1 million in PILs.

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e) THESL anticipates that the balances to be cleared from the Smart Meter deferral accounts in a future application will be a significant debit. Continuance of the $0.68 adder will serve to reduce the debit balance upon clearance.

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INTERROGATORY 94:

Reference(s): D1/T8/Sh7/pp.4-5

It is stated on page 4 when discussing suite metering capital expenditure amounts included for 2011 that "In consideration of anticipated requests for THESL to provide such services in both new and existing condominium buildings, the forecasted capital spend is $2.6 million in 2011."

On page 5, Table 2: "Suite Meter Installations Completed" shows a 2011 forecast total of 5,215 suite meter installations.

a) Please state whether the meters to be installed are smart meters and, if so, why this amount should be included in capital expenditures and not recovered through the smart meter funding adder.

b) If the response to a) is yes, please state whether this smart meter capital expenditure is incremental to THESL's proposed smart meter capital expenditure of $12.6 million.

RESPONSE:

a) Yes, they are smart meters. Since THESL views the installation of such meters to be part of core, post-rollout smart metering activities, THESL does not propose that they be subject to deferral account treatment. A key feature that distinguishes the installation of these meters from those installed under the rollout is that these meters do not replace previously existing meters.

b) The suite meter capital expenditure is incremental to (separate from) the smart meter capital expenditure.

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INTERROGATORY 95:

Reference(s): G1/T1/S1/p.12

THESL's evidence indicates that twenty-one (21) sensor units and seven (7) aggregators are scheduled for installation in August 2010. The units will be free from the vendor for testing purposes.

a) Does THESL intend to purchase these power line monitoring units if testing is considered to be successful?

b) If the answer to part (a) is yes, please indicate the approximate capital and operating funds that would be requested and when such costs would be requested for inclusion in the revenue requirement.

RESPONSE:

a) THESL does not intend to purchase the test units. However, if the testing is successful, THESL intends to purchase new units in 2011.

b) The funding requested for new units in 2011 is approximately $100,000, and is included in the 2011 capital budget.

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INTERROGATORY 96:

Reference(s): C1/T6/S1/p.10
G1/T1/S1/p.8

THESL indicates at the first reference above that the Feeder Investment Model (FIM) can be used to support business cases for other interventions that effect life-cycle cost, such as conversion to underground or some Smart Grid improvements.

a) Please state whether or not THESL has applied the FIM to the $2.68 million of feeder automation investments contemplated in Table 2: 2010 Smart Grid Projects of the second reference?
b) If so, how does THESL prioritize circuits chosen for feeder automation?
c) If THESL has not used FIM for this process, please explain.

RESPONSE:

a) THESL has not applied the FIM to feeder automation investments contemplated in Table 2 of the second reference.

b) THESL prioritizes circuits chosen for feeder automation based on parameters including reliability, feeder density, availability of transfer capacity, and level of station breaker control.

c) THESL does not prioritize circuits chosen for feeder automation based on FIM.

In reference to Exhibit C1, Tab 6, Schedule 1, page 11, the FIM has been implemented for only four asset classes so far, i.e., underground cable, vault transformers, underground switches, and network unit. The 2010 feeder automation

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project involves overhead switches only, and FIM support for smart grid improvements will require enhancements and improvements to the model.

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INTERROGATORY 97:

Reference(s): **C1/T6/S1/p.5**
D1/T9/S8/p.1
G1/T1/S1/p.1

At reference 1, THESL indicates that one of the emerging capital portfolios is Smart Grid.

At reference 2, THESL states that it plans to install a 4MW energy storage system at College municipal station in downtown Toronto. In reference to electric energy storage, THESL states at reference 2 that, "With the emergence of new storage technologies, this option is poised to become an essential component of the electricity infrastructure, particularly in this modern era of smart grid and renewable energy generation."

THESL indicates that benefits of the battery system include, among other things:

- Support service restoration
- Help facilitate the integration of intermittent, renewable generation sources as well as,
- Electric transportation into the grid within the GEA framework.

At reference 3, THESL indicates that, "smart development is in direct alignment with the GEA, where [used] for the purposes of accommodating the use of emerging, innovative and energy-saving technologies and system control applications."

In the context of the benefits noted above, on what basis does THESL consider the $30 million "Energy Storage Project" under the umbrella of its business-as-usual capital

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programs (under Emerging Requirements) rather than for inclusion in its Smart Grid Plan, or in THESL's subsequent GEA Plan and/or distributed generation plan?

RESPONSE:

This project is proposed principally as a distribution investment for power quality purposes and to mitigate the impact of loss of supply, and not a generation asset. From a distribution system perspective, this project provides similar distribution functionality as voltage regulators which have been used as distribution assets for decades with the added benefits of emergency backup supply, and interconnection points for additional mobile standby emergency generation. There are additional benefits associated with the energy storage capacity of this battery system that can be realized as smart grid technologies emerge on the distribution system. These are the additional benefits THESL refers to in the cited references 2 and 3.