REVIEW OF COST-OF-SERVICE METHODS OF MANITOBA HYDRO: Supplemental Report

for

Manitoba Hydro

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EXECUTIVE SUMMARY

This Supplemental Report concludes an independent evaluation by Christensen Associates Energy Consulting (CA Energy Consulting) of Manitoba Hydro's (MH's) cost-of-service (COS) methodology in response to regulatory requirements of the Manitoba Public Utilities Board (MPUB). The report provides additional evaluation of COS issues that have arisen since the submission of our original report in June, 2012.

The supplemental review focuses on three areas: 1) export sales, both cost allocation and treatment of export sales revenues; 2) transmission cost allocation; and 3) weighted energy calculation in generation cost allocation. This executive summary provides abbreviated statements of key issues and our recommendations.

ES-1. Export Sales

Issue: Embedded Cost Allocation to Export Sales. MH makes Dependable and Opportunity export sales, allocating fixed costs to Dependable sales and variable costs to both. MH makes some "hybrid" sales that, while firm in their commitments from the purchaser's perspective, do not depend directly on MH capacity. What costs should be allocated to these sales and, consequently, how they should be categorized?

Recommendation. MH should continue to allocate both fixed and variable costs to Dependable export sales and variable costs only to Opportunity export sales. Hybrid sales which are not backed up by MH resources should be classified as Opportunity sales.

Issue: Allocation of Net Export Revenues to Domestic Classes. There is no good cost basis for the allocation of Net Export Revenues. The current method uses Generation, Transmission, and Distribution (GT&D) cost, while a previous method used just G&T. What allocation method should be used?

Recommendation. As in the original report, we do not recommend a specific alternative to the current method. That report lists reasonable alternatives, but does not find that any alternatives provide an improvement adequate to recommend abandonment of the current approach.

ES-2. Transmission Cost Allocation

Issue: Cost Functionalization of Bipole III. MH's new HVDC transmission project, Bipole III, is designed to transmit power from remote northern generation sites to southern load centers. Should this line be functionalized as generation or transmission?

Recommendation. Assign (functionalize) all costs associated with Bipole III to generation. Allocate the costs associated with Bipole III according to the methodology for generation, the weighted energy allocator. This recommendation aligns with our recommended cost allocation approach for all direct facility costs associated with Bipoles I and II.

Issue: Cost Functionalization of Riel Station. Riel Station provides three transmission functions: 1) integration of power supply with loads; 2) improved reliability for MH's meshed network; and 3) voltage transformation. How should the station's assets and related costs be functionalized: transmission, or perhaps partial inclusion in other functions?

Recommendation. But for the DC inverter facilities (associated with Bipole III) situated at Riel Station, all costs associated with Riel Station should be functionalized as transmission, and allocated according to MH's current transmission allocation methodology (the average of the fifty highest hourly loads of the summer and winter seasons, calculated separately).

Issue: Cost Functionalization of DC Inverter Facilities Situated at Dorsey and Riel Stations. These stations contain DC inverter facilities that connect DC lines to the meshed network of MH. The inverter facilities include HVDC Reduction Special Protection Systems (SPS) that provide services to the grid as a whole. Should the inverter facilities, including the SPS assets, be functionalized as generation, transmission or both?

Recommendation. We recommend that Manitoba Hydro assign no less than 75% of the costs of inverter facilities located at MH's Dorsey and Riel Stations to generation; transmission should be assigned no greater than a 25% cost share.

Issue: Cost Classification of Interface with the United States. MH's transmission network reinforcement investments for the U.S. interface raise an issue of cost causation: are these costs caused by peak demand or energy requirements?

Recommendation. Supply-side contingency events, which network reinforcement investments are designed to minimize, potentially impose power outage costs on retail consumers and will likely occur with a strong random component. Accordingly, we recommend that MH use weighted energy, in lieu of energy without marginal cost-based price weights, because empirical evidence suggests (but does not prove) that, day-by-day, electricity consumption during peak load hours is more highly valued—i.e., outage costs are higher—than consumption during off-peak hours.

ES-3. Generation Cost Allocation: Weighted Energy

Issue: Components of marginal costs for use in weighted energy allocators. MH uses marginal cost-weighting of energy consumption as a generation cost allocator. Should marginal cost continue to be based on marginal energy cost or expanded to include MISO operating reserves cost? Additionally, should the definition of marginal costs also be expanded to include MISO capacity costs in some form?

Recommendation 1. We renew our recommendation that MISO operating reserves prices be included in the marginal costs used to compute weighted energy allocators.

Recommendation 2. We recommend that MH consider including capacity costs in its weighted energy allocator in order to capture, in full, long-term marginal generation costs. Marginal generation costs account for the demand-related share of the total costs of generation, and should be included along with weighted energy (and operating reserves) in peak period hours.

1. INTRODUCTION

1.1 Context and Purpose of the Supplemental Report

In 2011, Manitoba Hydro (MH or Company) commissioned a review of its cost-of-service (COS) methodology in response to regulatory requirements of the Manitoba Public Utilities Board (MPUB). MH retained Christensen Associates Energy Consulting (CA Energy Consulting) to conduct the review. The purpose of the review was to ensure that the Company's costing methodology conformed to industry standards, met the utility's specific needs, and continued to support the equitable pricing of utility services.

CA Energy Consulting submitted its COS methodology review report on June 8, 2012. The regulatory calendar did not permit immediate review of the report or MH's response to it. Since that date, developments in Manitoba and North American electricity markets have resulted in a need to review, or expand upon, the topics covered in that report. Generation and transmission plans of Manitoba Hydro, which had not been finalized at the time of the report, have become part of the utility's future. These plan include the Keeyask hydroelectric station and several significant transmission facilities (Bipole III and the Manitoba-Minnesota U.S. interface) and related substations (Riel). While these projects will provide long-term benefits to the Province of Manitoba, they will also cause the financial costs of MH to increase in the near term, costs which will appear in future prospective cost-of-service studies (PCOSS).

In addition, wholesale prices of electricity have remained at moderate levels since 2012, a path not contemplated at the time of the 2012 report. Indeed, average wholesale prices today are often below the prices paid by large retail customers (GSL > 100 kV) of MH. According to MH, this relationship may continue for several years, when export prices are expected to return to historical levels.

In 2014, MH initiated a process of internal review and stakeholder meetings, in which CA Energy Consulting participated, to enable a full discussion of these emerging topics. At the conclusion of this process, we engaged in further discussions with MH, and now submit this Supplemental Report covering the topics that have come to require additional review as a result of the above developments.

1.2 Outline of the Supplemental Report

The topics covered during the review process can be viewed as being related to three areas: treatment of export sales, classification of transmission assets, and the allocation of generation assets. The Supplemental Report provides a section on each of these topic areas.

2. TOPICS RELATED TO THE TREATMENT OF EXPORT SALES

2.1 Business Purpose of Export Sales and the Impact of the Present Export Outlook

The business purpose of MH is to provide reliable electric service at least cost to the retail customers in its service territory (referred to as "Domestic" customers). The Company undertakes investment in new facilities for this purpose. Like other integrated utilities, MH can sell any surplus power in wholesale markets. Unlike most utilities, MH's best generation investment is typically large hydraulic (hydro) facilities capable of storing significant production capability in their reservoirs. Investment in hydro facilities is highly indivisible ("lumpy"), giving rise to large power surpluses for potential export sale within wholesale markets. Moreover, several years may pass before MH's Domestic loads absorb the incremental hydro capacity. Thus, export power sales provide revenue supporting the overall business purpose of providing reliable electricity in a low-cost manner to the province. These export sales are reflected in PCOSS as lowering the cost to serve Domestic rate classes through an allocation of embedded cost away from retail cost responsibility and an allocation of net export revenue (sometimes referred to as surplus export revenue) back to Domestic rate classes.

MH's future addition of new generation facilities to rate base will result in a marked rise in capital charges on investment while, simultaneously, increasing export sales volumes, whose revenues can helpfully contribute to cost coverage. If the revenue from export volumes is large, it can reduce Domestic rates measurably, perhaps below the short-run marginal cost to serve Domestic rate classes. In addition, increased export volumes can magnify the effect of weather variability and the natural variability of wholesale market prices, resulting in increased year-by-year variability in the total financial costs allocated to MH's Domestic customers. Thus, while the business purpose of export sales is to provide revenues to defray the cost of new capacity that would otherwise fall on Domestic customers, that purpose may be somewhat frustrated by increased export revenue volatility.

Currently MH faces comparatively low export prices in the near term, as wholesale markets are expected to continue to be "capacity long" for a number of years. In the longer term, MH expects higher export revenues as service begins under new contracts, prices recover, and new hydro generation and supporting transmission assets provide for significant increases in capability. The PCOSS process faces the challenge of incorporating this expected increase in revenue and revenue variability from competitive wholesale markets in each respective PCOSS year.

Export sales can result in intense debate on the PCOSS treatment of exports. Stakeholders in Manitoba voiced concerns with Export class treatment in PCOSS after our initial report of June 8, 2012. Controversy over export sales treatment within future PCOSS studies may become even more intense as export sales revenues are used to offset the increases in rate base and cost of service that comes with the expected new plant in service.

The outlook for export sales and how they will affect Domestic rates is different today than it was in 2012. Therefore, it is appropriate for CA Energy Consulting to issue this supplemental report to further address the following salient Export class issues.

2.2 Embedded Cost Allocation to Export Class

The original COS Methodology report reviewed issues pertaining to the allocation of embedded costs to the Export "class" of sales and revenue assignment. Since that report, MH has clarified its categorization of its export sales revenue. The current (and still useful) categories are: 1) Dependable sales and 2) Opportunity sales. Dependable sales are generally for longer periods of time (typically greater than one year in duration) originate from dependable MH resources under lowest flow conditions, and they are a consideration in MH resource planning. Consequently, Dependable sales are allocated fixed and variable cost in PCOSS. In contrast, Opportunity sales tend to be for shorter periods of time (typically, but not always, less than one year in duration) and occur when water conditions permit export sales in excess of Dependable energy sales (which are supported by MH capacity). As a result, Opportunity sales are allocated variable cost only.

We believe it to be appropriate to revisit our original recommendation on embedded cost allocation to the Export class following a recent clarification in the range of export contracts, indicating that some firm sales are not backed up specifically by MH resources. These sales are instead firmed by resources of the firm energy *purchasers*.[1] These "hybrid" export sales do not influence the need for MH-owned resources. They should not influence embedded cost allocation other than recognition of variable costs in that allocation, and they should, therefore, be considered as Opportunity sales from a cost-of-service perspective.

If it were felt that hybrid sales did possess some possible causative influence upon the development of MH resources, and that influence were considered to vary in degree of causation by contract, some might suggest an alternative formulary approach in which a firmness index would be calculated for each specific sale and costs allocated on the basis of this index. Even if feasible, such calculations could be resource intensive, would likely be subject to differences of opinion in the derivation of the index, and could vary over time, all factors that are problematic for cost effective cost allocation. As a result, a policy approach that considers hybrid sales to be entirely Opportunity sales might still be the best answer.

In practice, export sales take place under a broad range of circumstances. Virtually all sales can readily be categorized in one of these two groups: Dependable and Opportunity. Subsequent PCOSS cost allocation to these two groups could employ any one of several alternative approaches:

- Allocate fixed and variable costs to both types of export sales.
- Allocate no fixed costs to either type of export sales, but allocate variable costs to both.
- Allocate fixed costs to Dependable export sales that are considered firm sales as backed up by MH resources, and allocate variable costs to all export sales.

Dependable export sales backed up by MH resources do influence MH's system plans. Past MH PCOSS studies have allocated both fixed and variable costs to Dependable export sales. In contrast, Opportunity sales do not affect MH system planning and have been allocated only variable costs. As a result, the first cost allocation method above would erroneously allocate fixed costs to Opportunity sales in spite of the fact that they do not cause such cost to be incurred.

The second approach is problematic in its implementation, since the allocation of variable costs only would result in significantly larger net export revenues (NER) than are currently being recorded. Larger NER margin could present MH with an increased allocation challenge, since larger NER act can act to drive down some Domestic rate class prices more than other rate

[1] An example of the ways in which firm sales can occur in ways other than via a conventional export sales transaction would be annual *purchases* by MH from U.S. markets that are used to supply Domestic needs in the winter months, yet are available for *sales* in U.S. markets in summer months.

classes. Further reductions of cost allocation to the Export class, creating larger NER to be allocated as a revenue requirement *reduction* to Domestic classes, might force some retail rate class prices below marginal cost. This undesirable result could be more likely if MH were to return to G&T allocation of NER. This could occur at certain times, or even on average, rendering incremental sales to some Domestic customers less attractive relative to export sales. Such a price signal runs contrary to a basic ratemaking principle.

Recommendation. MH should continue to allocate both fixed and variable costs to Dependable export sales and variable costs only to Opportunity export sales. This confirms current MH practice and the recommendation of the original report. It also conforms well with similar treatment by many other utilities in North America. Hybrid sales which are not backed up by MH resources should be classified as Opportunity sales.

2.3 Allocation of Net Export Revenues to Domestic Classes

NER consists of gross revenues from exports sales in the competitive wholesale marketplace minus the assigned and allocated embedded fixed and variable costs. This residual net revenue does not have a cost foundation as it is purely excess revenue from a competitive market. MH has applied a couple of reasonable cost-based methods for NER allocation to Domestic rate classes although illogical prices may sometimes result. In PCOSS04, MH allocated NER to Domestic rate classes based on generation and transmission (G&T) cost. Since then (and currently) MH has allocated NER using each Domestic class's share of generation, transmission, and distribution (GT&D) cost. The previous allocation rule possibly drew on the fact that generation and transmission facilities support and enable export sales but distribution does not. Unfortunately, this rule produced the illogical effect of reducing GSL > 100 kV customers' class revenue requirements so greatly that their prices were below short-run marginal cost. Partly because of this past problem, and partly because NER itself does not have a solid cost foundation, MH now uses the GT&D allocator to pursue a "fairness" objective in the resultant lowering of Domestic rates with NER allocation.

Some have questioned whether the current NER allocator is appropriate. GT&D allocation of NER instead of G&T allocation can have the effect of lowering PCOSS cost responsibility for those customers whose cost to serve is relatively high (i.e., customers receiving service at the distribution service level) and increasing cost responsibility for customers receiving service above the distribution level relative to the result using a G&T allocator. As mentioned above, using the G&T allocator in the past has had the perverse effect of reducing some rate classes' prices below incremental cost, while the more recent use of the GT&D allocator for NER has moderated this impact. The recently low NER due to lower-priced Opportunity sales, combined with the use of the GT&D allocator of NER, is at present providing prices reasonably above incremental cost in PCOSS.

Based upon MH's forecast, export prices are likely to remain low for the near term. However, the NER contribution (which lowers Domestic rates) may indeed increase in future PCOSS at a pace faster than some Domestic rates may grow. This may be problematic if some rates classes' allocated embedded cost end up below short-run marginal cost. The current GT&D allocator of

NER has accommodated export prices under a variety of circumstances resulting in reasonable Domestic rates.

Recommendation. The Export market is quite different today than prevailing when the 2012 report was prepared. Today the mid-term future appears to suggest higher embedded cost allocation to Dependable exports, growing Opportunity sales, and rising export revenue. Therefore, we believed it to be wise to have revisited our stated opinion on NER allocation to Domestic rates. Our conclusion is that, as in the original report, we do not recommend a specific alternative to the current method. That report lists reasonable alternatives, but does not find that any alternatives provide an improvement adequate to recommend abandonment of the current approach.

3. TOPICS RELATED TO TRANSMISSION SERVICE

3.1 Introduction to Transmission Issues

Under contemporary industry practice, the process of cost allocation includes the functionalization and classification of cost categories. Specifically, capital and non-capital costs attending the numerous facilities which constitute power systems are assigned to pre-determined functions (e.g., generation, transmission, or distribution), and classified according to the characteristics of the services provided (e.g., demand related, energy related).

Power systems are electrical circuits on a large scale, and the reason underlying the presence of specific facilities within circuits may not necessarily align directly with the generally accepted function for the class of facilities, as they are commonly known. In the case of transmission, the bleed of transmission functions into generation (and generation into transmission) calls for discerning view regarding cost allocation method, for selected facilities. Non-alignment of the function of specific facilities with the common functions of its class of facility abound; several examples can be cited, as follows:

- While the general function of substations is interconnection and voltage transformation, substation functions may reach further and more broadly to include metering, relays, and switchgear functions (interconnection) in order to maintain reliability across electrical circuits as a whole, as well as to avoid damage to generation equipment—turbines in particular;
- Regulation, spin, and non-spin reserve services, common to unbundled wholesale G&T markets, are provided exclusively by generation facilities, yet listed within open access transmission tariffs (OATTs);
- Voltage support provided by generation facilities is for the transport of real power; and
- Phase shifters allow for the control of flows on lines, obtaining results akin to redispatch, which is exclusively generation.

It is thus important to take a discerning view of transmission, and examine the function and activity of specific facilities or groups of facilities (e.g., large substations that provide multiple functions). It may be inappropriate to functionalize and classify all transport facilities as transmission and/or apply a common cost allocation method, without exception. In a word, cost allocation of transmission requires thoughtful review, seeking to ferret out and discover where selected facilities depart significantly from the commonly accepted role of transmission.

To this end, the supplemental report takes up cost allocation methodology with respect to several of Manitoba Hydro's transmission facilities including Bipole III, Riel Station, and the Inverter Facilities Situated at MH's Dorsey and Riel Station. In addition, we elaborate more fully on Manitoba Hydro's interface facilities with the Eastern Interconnection. For transmission (particularly for Manitoba Hydro's transmission), the starting point for the determination of cost allocation methodology is a thorough understanding of:

1. the key features of MH's power system planning criteria, and the functional role assumed by selected transmission facilities;
2. the characteristics of the electricity markets in which MH takes part, as service provider and also as purchaser of wholesale services.

3.2 Key Features of MH's Power System

Electricity supply for Manitoba Hydro's power system is produced predominantly by MH's hydraulic facilities, which reside far to the north of MH's main retail loads, concentrated in the Winnipeg area. For the purpose of cost allocation, MH's hydraulic resources present two points of concern. First, the internal costs incurred by MH to operate its fleet of hydro plants are highly concentrated in the service of physical capital (return on and of investment); only a small share of total costs are variable operating costs. Second, the all-in costs of MH's hydro facilities possess long-term total cost advantages with respect to alternative power supply technologies.

The realization of this highly favorable result does not come about easily and it useful to touch upon certain concerns, driven by the overarching capital and operating features of hydraulic technology. First, sizable hydraulic facilities are unusually capital intensive, with high levels of capital indivisibility determined by the nature of the physical capital. It is necessary to construct much of the civil structures (dam, intakes, concrete encased penstock, tail race, etc.) in order to obtain scale economies across the full set of turbines. The civil structures are highly capital indivisible and costly; however, the incremental costs of installing individual turbines is comparatively modest. Accordingly, it is generally appropriate to install the complete set of turbines, once the civil structures are in place. As a consequence, for sizable hydraulic facilities of hydro-dominated power systems, retail prices measured in nominal dollars can assume an unusually lumpy, non-smooth temporal pattern over years, particularly where retail prices are determined according to original accounting costs.

An important operating feature of hydro-dominated power systems is the issue of inherent supply risk. Where a fleet of hydraulic power facilities draw upon a common, regional watershed, it is difficult to diversify the risks associated with the variation in year-by-year patterns of precipitation. As a consequence, hydraulic-dominated facilities should carry comparatively high levels of reserve capability in order to accommodate variation in water flows. Reserve capability can be in the form of call provisions of wholesale contracts, options to purchase outside power, and retail curtailment options. However, Manitoba Hydro is in the enviable position, often, of having a plentiful supply of unusually low cost power; accordingly, MH is an active high-volume seller within wholesale (MISO) markets for generation services.

Because of the remote location of MH's hydro facilities, the Company must "get power to market." Hence, MH has put in place dedicated power transport facilities in the form of the direct current (DC) facilities known as Bipole circuits I and II. Bipole I and II utilize a common route and constitute essential components of Hydro's generation, including converter facilities (conversion of alternating power to DC) located within MH's collector system for the Kettle, Long Spruce and Limestone generating units, and inverter facilities located within MH's Dorsey Station, situated at the northwest doorstep of the Winnipeg urban area.

Key observations regarding MH power supply include: the concentration of hydro supply in the far north; of Bipole I and II following a common route/corridor; energy-constrained domestic supply; DC power flows into a common location (Dorsey Station); and of MH's limited interface capability with the Eastern Interconnection.[2] As a result, all of Manitoba remains comparatively vulnerable to, potentially, extended, abrupt supply interruption, at major short- and long-term economic costs. As a consequence, MH is taking two strategic actions:

- Construction of a third DC circuit, additional to Bipoles I and II, to interconnect hydro power supply in the north to the Winnipeg area in the south, along a separate route. This third DC circuit is referred to as Bipole III.[3] Bipole III will be interconnected with MH's meshed network at the recently completed Riel Station; and
- Expansion of the MH interface with the Upper Midwest area of the Eastern Interconnection, referred to as the Manitoba-Minnesota Transmission Project (MMTP), a 500 kV facility, including reinforcement of the US portion of the transmission corridor.

3.3 Characteristics of Power Markets in Which MH Participates

Like most power markets, the retail electricity market served by Manitoba Hydro is characterized by a mix of residential and business markets, including mass market commercial sectors and large industrial customers. Electricity demand served by Manitoba Hydro has substantial seasonal patterns. A result of substantial electric heating loads, January weather-normalized electricity consumption (as billed) is expected to be approximately 1,200 GWH above that of sales during the summer months.[4] In contrast, the retail service providers within the MISO RTO footprint experience peak electricity demand during the summer months. Prices follow loads; as a consequence, MH is well positioned to export power during the summer, when hydro power is abundant and prices are highest.

[2] Manitoba Hydro's interface with the U.S. consists of four facilities including Glenboro South to Rugby (230 kV), Letellier to Drayton (230 kV), Richer South to Moranville (230 kV), and Dorsey (Riel) to Forbes (500 kV).

[3] MH's Bipole III transmission project includes a 2,000 MW converter station in the north (Keewatinohk C.S.) in order to interconnect with MH's northern collector system. The northern interconnection will involve one new 230 kV AC circuit between the Long Spruce Generation Station and Keewatinohk, and four new 230 kV AC circuits between Henday and Keewatinohk. The southern interconnection consists of a 2,000 MW inverter facility situated at Riel Station, located toward the Southeast of Winnipeg.

[4] For forecast year 2019/2020, as reported in MH's *2014 Electricity Load Forecast.*

3.4 Bipole III

Power system reliability, *ex ante*, is a matter of sufficient supply of reserves available to load centers, in view of expected peak loads. Reliability events can arise because of unexpectedly high load levels, given the available supply, or because of supply-side events resulting in supply shortages. For fairly mature, largely meshed power systems, further investment in transmission is driven by the need for facility replacement, improved observability,[5] and expansion of capability (upgraded transformers, increased compensation, larger conductors, or additional circuits). Within mature systems, load-driven expansion is predominantly a matter of satisfying peak loads, as the transport basis of expansion is largely complete. For this reason, it is arguably appropriate to assign, within cost allocation, the costs of conventional network transmission to peak loads.

Bipole III, however, is driven by supply-side reliability concerns.[6] In view of the limited capability to import power, Manitoba's bulk power system remains fairly susceptible to supply interruption, as Bipole circuits I and II follow a common corridor feeding into a common destination near Winnipeg (Dorsey Station). As a consequence, in the absence of Bipole III and Riel Station, a highly disruptive power loss event could engulf the regional economy, perhaps for an extended period—at great economic and social costs to Manitoba.

For the purpose of cost allocation, key observations are as follows:

- Much like Bipole circuits I and II, Bipole III interconnects hydro generation to MH's main load center and thus serves, exclusively, an interconnection function, linking generation to loads, with comparatively low line losses.
- Because Bipole facilities are DC circuits, flows on lines can be controlled.
- Loads on MH's Bipole facilities vary in lock step with respect to the power injection of power into the DC power converters situated at the northern collector system (the point of AC to DC power conversion). In other words, observed flows on the Bipole circuits are not the net result of a set of counterflows involving multiple points of power injection and withdrawal.
- The MH Bipole facilities are dedicated circuits and integral to generation, with one-way flows from north to south. Bipole facilities have no load withdrawals (or injections) along the circuits. The north-to-south direction of power flows is never reversed.

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[5] "Observability" refers to the level (degree) that the status of large power systems can be observed. Observability involves real-time measurement of key parameters (e.g., voltages, power angles) at selected locations. When coupled with mathematical algorithms, observed parameters allow system operators to monitor the status of the network in near real time, with acceptably high locational density.

[6] Reliability can assume various physical and dollar cost metrics. Commonly applied methods for power system planning include the well-known one-in-ten-year criteria: under n-1 configuration, the G&T system can serve the total firm peak demand over repeated random draws of system supply conditions, but for one draw in ten, or 2.4 hours for one day each year. Such an approach, often referred to as Loss of Load Expectation (LOLE) is not the full story: single outage events can assume a variety of durations (hours, days), and depth of the loss of power (MW). Accounting for duration and depth of power loss, consumer outage costs (economic losses) can assume modest or very large magnitude.

Along with Bipole I and II, the Bipole III facility has several attributes and features which distinguish it from conventional high-voltage AC transmission facilities alluded to above: long-term supply reliability that parallels investment in MH's northern generation services; single-directional flows; distinguishing operational characteristics; and close integration to MH's generation facilities in the north.

Recommendation. Assign (functionalize) all costs associated with Bipole III to generation. Allocate the costs associated with Bipole III according to the methodology for generation, the weighted energy allocator. This recommendation aligns with our recommended cost allocation approach for all direct facility costs associated with Bipoles I and II.

3.5 Riel Station (Reliability Project and Associated Facilities)

The Riel Station Reliability Project consists of one of two asset groups of MH's facilities at Riel Station. The Reliability Project fortifies MH's meshed network with two general functions:[7]

- *Improved Reliability for MH's Meshed Network:* In addition to providing for improved power supply integration, Riel Station enables improved flow patterns and thus improved reliability on MH's high voltage AC circuits, and thus supports the overall meshed network serving the southern Winnipeg area. The completion of Riel Station calls for the sectionalizing of MH's Dorsey to Forbes 500 kV interface link, and of the Ridgeway to Richer 230 kV circuit. Riel provides the basis for expanded capability and reinforcement of the meshed network. Currently, southern Winnipeg is largely supplied by a system of 115 kV lines and substations. Upgrades include plans for a 230 kV circuit between St. Vital and La Verendrye Stations.
- *Voltage Transformation:* Riel Station provides voltage transformation services—transforming 500 kV power supply to 230 kV power, necessary insofar as 230 kV facilities along with the 115 kV network are the backbone of MH's transmission network within the Winnipeg area and beyond.

These two functions are common to AC networks and undertake the standard task of facilitating power flows throughout the grid. Accordingly, it would seem that Riel Station, except for the inverters, can be functionalized as transmission.

Recommendation. But for the DC inverter facilities (associated with Bipole III) situated at Riel Station, all costs associated with Riel Station should be functionalized as transmission, and allocated according to MH's current transmission allocation methodology (the average of the fifty highest hourly loads of the summer and winter seasons, calculated separately).

[7] Riel Station is comprised of two separate projects: 1) Riel Reliability Project, and 2) Bipole III Reliability Project. The Reliability project is complete and entailed establishing the Riel Station site, installing 230 kV and 500 kV switch yards, installing a 230 kV to 500 kV transformer bank, sectionalizing the existing Dorsey- Forbes 500 kV AC MH-U.S. interconnection, and sectionalizing two existing 230 kV lines (Ridgeway-St. Vital lines R32V and R33V). The second project involves the construction of a converter station at Riel for the purposes of inverting HVDC power transported along Bipole III. This second portion of the station has a projected in-service date of 2017.

3.6 DC Inverter Facilities Situated at Dorsey and Riel Stations

As with all direct current transmission lines operating within AC networks, Manitoba Hydro's DC facilities require power conversion capability at the north end of the two Bipole routes, and inversion facilities at the points of interconnection within MH's meshed AC network, including Dorsey Station (for Bipole I and II), and Riel Station (for Bipole III). For purposes of cost allocation, Manitoba Hydro assigns the inverter facilities to transmission, and allocates the costs accordingly (peak loads). However, the inverter facilities are dedicated to the bipole facilities, which in turn is clearly for the interconnection of generation.

Discerning cost allocation requires further exploration of the function of inverter facilities at Dorsey and Riel Stations, as the engagement and role of these two facilities, MH's main substations, are considerably larger than other stations of the MH bulk power system. As discussed above, Manitoba Hydro's interface with the U.S. grid includes four major circuits/routes, three 230 kV circuits and one 500 kV circuit. In addition, MH's power system consists of other extended 230 kV radial circuits, sourced to the Winnipeg meshed network. Large power systems generally, but long lines in particular, are susceptible to conditions of instability and possible separation, as a consequence of power disturbances of various types, which give rise to unexpected changes in angles at various locations within the system.

Disturbances which lead to power oscillations (a condition of potential instability) within transmission circuits are a constant concern. Instability arising from disturbances can be precipitated in several ways, including unexpected faults or planned closure of circuits that have been out of service for routine maintenance. The potential for instability rises nonlinearly with respect to loads. It is thus necessary for power systems to have in place control technologies to dampen transient instability when it arises, in real time. While managing transient stability is highly specific to each system (control area), transmission systems cannot be safely operated, often, anywhere near the thermal limits on lines, absent specific technologies to maintain stability—to keep systems within stability limits.

Technologies to manage stability include well-known series compensation devices, situated strategically within power system networks. Series compensation, or expanded circuits also, are costly. Because of the presence of its DC inverters, Manitoba Hydro is a special case, however. The inverter facilities include special equipment, referred to as a HVDC Reduction Special Protection Systems (SPS). SPS utilizes the fast-responding controls inherent in Manitoba Hydro's HVDC systems. Coupled with other control equipment, the SPS enables MH to satisfy transient stability limits at moderate to high system loadings, at remarkably reduced costs compared to other control methods to maintain stability.

This begets the question: what is the worth of the SPS control features of the DC inverter facilities, measured in terms of loss of the use of the full capability of the system?[8] Reduction in the use of the transmission system also implies the loss of the use of hydro generation situated

[8] Essentially, high loads across network facilities may cause power systems to exceed stability limits; reduced flows on facilities are necessary to satisfy limits.

to the north. The only way to address the question is through power system simulation studies; MH has addressed this question with such studies.

Results of power system simulation studies are highly specific to the model parameters, system conditions, and assumptions under which the studies are conducted: changes in parameters change the analysis results. Nonetheless, MH's studies suggest that, in the absence of the configuration of the Dorsey inverters with SPS equipment, a large proportion of the MW flow capability of MH's power system could not be utilized without breaching reliability standards set forth by the North American Electric Reliability Corporation. In brief, flows on the HVDC system would be approximately halved: MH could utilize its northern hydro power facilities and its HVDC lines (Bipole I and II) at approximately one-half of the available 3,300 MW. With the SPS equipment in place, MH can utilize the remaining capability, such that the full power flow capability of the bipole facilities can be employed to transport power. Obtaining utilization of the full capability of Bipole I and II while also satisfying transient stability requirements constitutes a differential of approximately 50% utilization with respect to full capability (3,300 MW). This differential of increased utilization, approximately 1,700 MW, affects both the delivery of power from MH's northern generation facilities and power flows within the meshed AC network.

In summary, configured with the SPS equipment, the DC-AC inverters allow for conversion of DC power to AC, and the full utilization of the bulk power system. This suggests that the costs of the inverters and the SPS stability management equipment should be jointly functionalized as generation and transmission.

The reasoning is as follows: MH is able to use much of its northern hydro power and Bipole I and II facilities absent the SPS equipment. Hence, this share—i.e., load share—of cost of the inverter facilities (at Dorsey and Riel also) is clearly related to generation; the inverters, absent SPS equipment, have no impact on MH's meshed network. The presence of SPS, however, results in the full utilization of MH's G&T system, a differential approximating 50%. Because SPS is inseparable from the inverters, it appears plausible to allocate the remaining 50% cost share to generation and transmission, with no less than half of the remaining share—effectively, 25% of total costs—assigned to generation.

Recommendation. We recommend that Manitoba Hydro assign no less than 75% of the costs of inverter facilities located at MH's Dorsey and Riel Stations to generation; transmission should be assigned no greater than a 25% cost share. Our recommendation is based on the incremental utilization of MH's bulk power system, including power generation and transport, facilitated by SPS and related controls within the inverter facilities. So equipped, the inverter facilities provide the capability to maintain system stability at both typical and fairly high levels of load.

3.7 Interface with the United States

As described above, Manitoba Hydro's interface with the U.S. grid consists of three 230 kV circuits supplemented by one 500 kV circuit, commonly referred as the Dorsey (Riel)-Forbes route. In view of the vulnerability of the MH power system—and retail consumers—to major power outages over an extended duration, MH is currently reinforcing its power system. In addition to Bipole III and Riel Station, MH's transmission expansion plans includes a major 230 kV circuit following Manitoba Hydro's South Transmission Corridor, completing the 230 kV loop around Winnipeg, and expansion of the MH interface with the United States. As mentioned above, expansion of MH's U.S. interface is facilitated by a second 500 kV circuit, the Manitoba-Minnesota Transmission Project (MMTP).

The new MMTP facility, scheduled for completion in 2020, will follow MH's South Transmission Corridor (within the Winnipeg area), and stretch south to interconnect with Minnesota Power's 500 kV circuit, referred to as the Great Northern Transmission Project, located near Roseau in northern Minnesota.

MMTP provides expanded capability for the transfer of power flows between MH and the U.S. Eastern Interconnection. Expanded capability is proportionately large: MH studies of simultaneous power flows, confirmed by MISO, indicate that, with MMTP in place, export capability by MH to the MISO region will increase by approximately 900 MW; more importantly, power import capability is expected to increase by approximately 750 MW—essentially doubling MH's capability to import power for the purpose of managing supply-side contingency events and, on rare occasions, to further minimize power system operating costs.

As we discuss above, transmission system reliability for MH is unusually critical because of the comparative isolation of the load centers from power generation. The process of transmission expansion planning at MH complies with the transmission planning criteria set forth by the governing authority for power system reliability, the North American Electric Reliability Corporation (NERC). These criteria include n-1 and n-2 criteria: power systems should remain intact (all firm loads served) following first contingency events involving the loss (outage) of the most highly-valued (for reliability) system component. Controlled load shedding is allowed under the n-2 criterion (loss of the two most valuable components of supply within power systems. Loss of service from Bipole I and II would result in attenuated power supply, including northern hydro power transmitted by Bipole III, with capability of approximately 2,000 MW; AC interconnected generation of approximately 1,400 MW; and firm import capability limited to approximately 700 MW without MMTP. If such contingency events (i.e., Bipole I and II out of service) were to occur during peak winter loads (projected to approximate 5,100 MW in 2020), it appears to us that Manitoba would face, potentially, a major supply-side induced power outage, perhaps for an extended period. Our reading of available evidence is that the U.S. interface is necessary for reliability. In the absence of the U.S. interface, MH would be in the position of a potential power supply delivery shortfall.[9]

For near-term years, however, the incremental capability obtained with MMTP (500 kV) may not be immediately necessary in order to satisfy reliability for Winnipeg and the extended region. However, the scale economies associated with transmission conductors, towers, and associated equipment are very large. Hence, it is often appropriate to put in place larger, perhaps somewhat oversized equipment, as the incremental cost of doing so is small. In

[9] The discussion is necessarily laced with a degree of conjecture. While we cannot be absolutely sure, the reasoning appears to support intuition nonetheless: Bipole III and MMTP appear to be necessary, absolutely, with Bipole III or comparable capability obtained through other means of singular importance.

addition, the larger-sized conductors—say, 500 kV facilities in lieu of 230 kV facilities—generally increase system stability, a consequence of reduced impact to unanticipated faults, as the likelihood that facilities "trip off-line" from transients is attenuated.

Recommendation. On balance, Manitoba Hydro's U.S. interface, including the expanded capability obtained with the MMTP, contributes significantly to satisfying reliability requirements. No doubt, MH's U.S. interface facilities provide, simultaneously, joint capability in the form of reliability and energy transfer capability. However, if MH was precluded from engaging in export sales, the interface facilities would remain necessary—for the reliable provision of power supply over the long term.[10]

Supply-side contingency events, which network reinforcement investments are designed to minimize, potentially impose large power outage costs on retail consumers and will likely occur with a strong random component. Weighted energy-based allocation accurately captures the time pattern of foregone value of the consumption of electricity (outage costs) as a consequence to supply-side events. Thus, the costs of Manitoba Hydro's interface facilities should be allocated according to weighted energy. We recommend that MH use weighted energy, in lieu of energy without marginal cost-based price weights, because empirical evidence suggests (but does not prove) that, day-by-day, electricity consumption during peak load hours is more highly valued—i.e., outage costs are higher—than consumption during off-peak hours.

4. TOPICS RELATED TO THE ALLOCATION OF GENERATION COSTS

4.1 Introduction

Our original cost allocation approach concurs with Manitoba Hydro's approach for allocation of generation costs, referred to as Weighted Energy (the marginal value of energy by time period, with this value reflecting MISO prices of energy, while accounting for other factors). We continue to view Weighted Energy favorably. The purpose of this discussion is to elaborate on and further clarify the discussion of weighted energy contained in our original report. Discussed below is inclusion of Operating Reserve Prices and, separately Capacity Costs within MH's weighted energy allocation methodology.

4.2 Weighted Energy, a Marginal Cost Basis of Allocation

For some time, Manitoba Hydro (MH) has allocated the financial costs of its generation resources, including Bipole I and II, according to its Weighted Energy method. As we have mentioned in discussions, as well as in our cost allocation report, we find weighted energy to be an attractive approach for allocation of generation costs. Under Weighted Energy, the differences in the short-run relative cost to serve across the peak, shoulder, and off-peak periods (and also across seasons) are determined on the basis of marginal cost. In essence, differentiating retail class prices according to differences in the marginal cost to serve

[10] It would seem that MH could, alternatively, install some 1,500 MW of generation capacity near the Winnipeg area, in lieu of the interface facilities. It is highly likely, however, that such a resource strategy would prove more costly, in addition to foregoing the capability to profitably export power to the U.S.

integrates pricing efficiency with financial costs (revenue requirements), and has a certain intuitive appeal, for a couple of reasons.

Setting prices according to properly defined marginal cost is generally recognized as facilitating efficient market outcomes. Driven by self-interest, consumers (the demand side of markets) use electricity up to the level at which the value to the consumer arising from a small increase in consumption approximates the price paid.[11] Similarly, generators provide incremental supply up to levels where incremental supply costs approximate market prices. The market thus produces an optimal amount of consumption and production. This neoclassical result generally holds providing that markets are workably competitive—as price takers, the actions of any single supplier (or consumer) have no measurable impact on the prices received (paid). This first-best result is obtained to the degree that markets contribute to surplus value, a measure of wellbeing or, in the parlance of economics, economic welfare.

Second, weighted energy provides an effective cost metric to differentiate retail prices by timeframe, in the form of time-of-use and, to a lesser extent, seasonal rates. As electricity demand studies demonstrate, movement of load from high- to low-cost periods is determined predominantly by relative prices, and only secondarily as a function of the overall price level. For this reason, if the relative price differences between peak and off-peak periods follow marginal cost patterns, gains in pricing efficiency are obtained, even when the level of financial costs departs from marginal costs. This result is also likely to hold even if financial costs are fairly distant from marginal cost. Certainly, further integration of marginal cost into cost allocation and tariff design is worthy of consideration.[12]

[11] At a practical level, market efficiency attending marginal cost-based pricing is contingent upon two conditions. First, no single entity can sustain prices at levels which depart from marginal costs through the exercise of market power. Hence, market prices reflect marginal supply costs. Second, prices for substitute commodities—e.g., natural gas—also approximate the respective marginal supply costs. Both conditions generally hold, though only approximately, across North American energy markets. In the case of condition 1, North American wholesale electricity prices are workably competitive during most timeframes and in most areas. In the case of condition 2, it is generally accepted that, in view of the presence of many producers, wholesale natural gas prices do not depart significantly from marginal production costs, although the recovery of delivery costs (pipeline and local T&D costs) in retail volumetric prices may result in sizable distortions from short-run marginal gas costs, where spot prices serve as the appropriate proxy. In addition, delivery constraints may cause very high spot gas prices for selected areas—e.g., New England during the winter of 2014.

[12] Along with accompanying computations, this standard result is described succinctly in the well-recognized modern treatise *The Theory of Public Utility Pricing* by Stephen J. Brown and David S. Sibley (1986): "Because producer surplus plus consumer surplus rises as price moves toward marginal cost …total surplus [i.e., market measure of wellbeing] is maximized when price is set equal to marginal cost," page 29. Similar interpretations, though different results, are analytically reached or discussed elsewhere, including Baumol and Bradford, "Optimal Departures From Marginal Cost Pricing," *American Economic Review*, 1970; Kenneth E. Train, *Optimal Regulation*, 1994; James C. Bonbright, Albert L. Danielson, and David R. Kamerschen, *Principles of Public Utility Rates*, 1988; Michael A. Crew and Paul R. Kleindorfer, *The Economics of Public Utility Regulation*, 1990; and Robert B. Wilson, *Nonlinear Pricing*, 1993.

4.3 Augmenting Weighted Energy: Operating Reserves Prices

We have previously recommended that MH consider incorporating MISO operating reserve prices within its weighted energy allocation approach. Such an addition is conceptually appropriate as operating reserves are a necessary element of the short-run marginal costs of generation services. In view of current magnitudes, inclusion of operating reserve prices within marginal costs (SEP prices which in turn are derived from MISO regional prices) would have modest impact, at least in the current environment of abundant planning reserves at a regional level. Inclusion of marginal reserves costs now would have no immediate cost impact, would improve the methodology, and would permit automatic revision of weights as reserves tighten.

Recommendation. We renew our recommendation that MISO operating reserves prices be included in the marginal costs used to compute weighted energy allocators.

4.4 Augmenting Weighted Energy: Capacity Costs

In view of recent developments in the structure of MISO wholesale markets—namely, the appearance of voluntary capacity markets—capacity costs should also be considered for inclusion in MH's weighted energy calculations. Prior to the appearance of MISO capacity markets, capacity costs were accounted for, arguably, by the scarcity rent content implicit within observed energy prices. That is, observed energy prices clear at levels above marginal energy cost during timeframes of comparatively high loads. Scarcity rents accumulate to levels such that, under equilibrium conditions, the sum of scarcity rent content in energy prices[13] over the course of an annual period approximates the annual carrying charges on capacity. Essentially, scarcity rents serve as the shadow prices to capacity costs.

Reaching equilibrium conditions, such that the quantity of supply is well balanced with the expected level of demand over forward periods,[14] proves to be highly elusive because of the inherent properties of power systems.[15] The reasons for fairly wide departures from well-balanced supply-demand equilibrium are several. Real-world examples abound: some years have unusually high temperatures (2012) while other years are unusually cool (2014); regional generation availability is high one year while other years are troubled with availability[16] or

[13] Under simultaneous auctions for energy and reserves—sometimes referred to as co-optimization—reserve prices approximate the marginal opportunity costs incurred by generators by participating in reserves, a direct result of the sale of power into energy markets. As a consequence, scarcity rent content within energy prices generally obtains higher reserve prices also.

[14] Supply-demand equilibrium is obtained when the marginal costs of capacity ($/kW-year) are equal to marginal outage costs, equal to the product of expected unserved energy (EUE) and value of lost load (VOLL) to retail consumers. Contemporary surveys suggest that VOLL resides within the range of $3.00 to $12.00 per kWh, for most economic sectors. A well-known Canadian researcher, Roy Billinton, has published numerous studies which report outage cost survey results.

[15] Namely, the supply-demand balance condition: power supply is equivalent to electricity demand in each time moment.

[16] As an example, utilities in the American Southeast had difficulty cooling coal-fueled generators during drought years 1986-1987 because of low flows in regional rivers.

experience major difficulties with larger generators;[17] and the expected path of future primary fuel prices may change abruptly—e.g., the fall of 2011. In addition, year-over-year event risks can be amplified by overarching changes in the macro economy—e.g., the unexpected and deep U.S. recession beginning in late 2007 has resulted in an extended capacity-long condition across the entire Eastern Interconnection, and is manifested in comparatively low wholesale electricity prices with little or no scarcity rent content.

In brief, rent content within prices can vary greatly from one year to another; hence, independent private generators, and incumbent utilities also, [18] cannot readily depend upon a steady stream of scarcity rents inherent in energy prices over forward years, to fund the capital charges on investment, at least in the absence of long-term forward contracts with an incumbent retail service provider or large industrial consumer. In addition, the problem of variation in scarcity rents is made worse by the issue of price level constraints, as regulators imposed price and bid caps on short-term energy markets. In brief, high year-over-year variation in rents coupled with price constraints would appear to precipitate a potential shortfall in capacity. As a consequence, there has been considerable concern among participants within eastern U.S. markets[19] that energy-only markets will not beget sufficient capacity to satisfy reliability requirements. For this reason, the notion of capacity markets to provide supplemental revenue flows to generators has gained traction, since 2001 approximately. The New York ISO and PJM have had capacity markets (i.e., capacity auctions) in place for several years, while the New England ISO and MISO have only recently implemented capacity auction processes.

The inclusion of explicit capacity costs within weighted energy allocation precipitates an issue: residual scarcity rent content within observed energy prices implies a potential double count. That is, the inclusion of explicit capacity costs, however determined, along with scarcity rents inherent within energy prices suggests that the total cost of capacity may be over-accounted for within the weights, possibly introducing a distortion among peak, shoulder, and off-peak timeframes. We opine that, for three reasons, any distortion resides within the range of very modest to vanishingly small. First, note that Upper Midwest prices reflect locational price differences, a consequence of transmission constraints across the MISO region. Transmission constraints are present in most hours, though the constraints may only modestly separate markets.[20]

[17] As an example, the damage to the reactor dome of Progress Energy Florida's Crystal River Unit 3 was sufficiently serious to cause the retirement of the unit, in view of high reinvestment costs necessary to repair the facility.

[18] Incumbent utilities and their retail consumers face equivalent investment risk, as the decision to build new capacity in lieu of the purchase of power from wholesale market (buy vs build) is benchmarked again expected future prices in the region.

[19] In this context, eastern markets refers to Maryland, New England, New Jersey, New York, Ohio, Pennsylvania, and Virginia.

[20] The Arpin-Eau Claire 345 kV flowgate along Wisconsin's western interface experienced very high incidence of Transmission Load Relief calls (TLRs) during the 2001–2003 timeframe.

Generally speaking, when loads within the MISO footprint are high—and thus prices are comparatively high—Upper Midwest prices remain comparatively low with respect to other areas of the MISO footprint. Essentially, the Upper Midwest area is upstream from most of the transmission constraints, where power generally flows from West to East. Because it is these high-load timeframes when scarcity rent content is substantial, it is likely not to amount to much, in the Upper Midwest area. Essentially, Upper Midwest prices trade close marginal running costs even during high-load periods. This view is borne out empirically within the recent MISO Market Monitor Reports.

Second, MISO capacity auction prices are currently low and reflect very limited participation, suggesting that, since 2009, scarcity rent content is similarly small, even in the absence of capacity markets over much of this period. Third, the introduction of capacity markets will likely push scarcity rents content to near zero in the long-term. Taken as whole, it is highly unlikely that a double count is either present or at a level that warrants concern.

In summary, the presence of capacity markets implies that generators are assured of a supplemental flow of revenue obtained through capacity auctions, easing the burden of justifying and funding new generation. More capacity is likely to be installed—at least initially—and total generation costs are likely to be lower as a consequence. However, scarcity rent content within energy prices over forward periods will surely be reduced, a result of increased supply. Similarly, we can expect capacity margins in the longer term to assume somewhat higher levels as lower risks translate into lower carrying charges on capacity, other factors held constant. In short, it is appropriate for MH to consider the possible inclusion of a measure of capacity costs within its weighted energy allocator, as capacity costs will not likely be fully accounted for implicitly (as scarcity rents) within energy prices, if at all, on a going-forward basis.

4.4.1 Integrating Capacity Costs within Weighted Energy

The inclusion of capacity prices within MH's weighted energy methodology can be facilitated in two analysis steps, determination of annual capacity prices/costs ($/kW) and assignment of costs to timeframes, as discussed below:

Determination of Capacity Prices/Costs. The first approach option is for MH to utilize current period MISO capacity prices, a recent result of MISO's auction process. As with energy prices, capacity auction prices reflect contemporary expectations of the supply-demand balance over the forward periods covered by the auction. However, with the continued supply-long position across the Eastern Interconnection, auction prices over the forward period can remain well short of the all-in incremental cost of capacity, stated on a $/kW-year basis.

A second approach, as demonstrated by Manitoba Hydro during the December 12 discussion with stakeholders, is to forego the use of capacity auction prices and, instead, apply an all-in cost approach. All-in marginal capacity cost is essentially the least-cost means by which reliable capacity can be provided; the current consensus holds that the installed cost of a stand-alone simple cycle combustion turbine (CT) generator, stated on $/kW-year basis, serves as an appropriate proxy for marginal capacity cost. Under this approach, the current annual cost of capacity is approximately $60-$70 per kW-year, if funded privately. Because much of the annual cost of a CT is occupied by the carrying charges on capital, the annual $/kW charges may be considerably less than this level for Manitoba Hydro.

4.4.2 Assignment of Costs to Timeframes

Because capacity is on the margin during peak load periods, capacity costs can be assigned equally across peak period hours or, better yet, differentiated according to system loads. Several *ad hoc* hourly cost allocation methods are available, two of which we find attractive, as follows:

- *Hourly Estimates of Expected Unserved Energy (EUE):* Expected Unserved Energy (EUE) draws upon well-established planning tools used to estimate the need for additional capacity, where reliability is simulated over numerous generation and load conditions, using Monte Carlo methods. System planning models often characterize reliability in terms of two well-known metrics: Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). LOLP and LOLE can serve as proxies for expected unserved energy.
- *Relative Hourly Loads:* The second approach weights hourly loads of an annual timeframe according to the proximity of individual hourly loads to the annual load peak.

Recommendation. We recommend that MH consider including capacity costs in its weighted energy allocator in order to capture, in full, long-term marginal generation costs. Marginal generation costs account for the demand-related share of the total costs of generation, and should be included along with weighted energy (and operating reserves) in peak period hours. The inclusion of capacity cost within peak periods constitutes a *demand-related allocation element*, within energy/demand cost allocation methods.

Estimates of capacity cost can be determined in several ways. We find MH's first-year cost of a simple cycle combustion turbine generator, derated by a reference discount for curtailable load, to be appropriate for the purposes at hand, the allocation of embedded costs of generation and (selectively) transmission facilities to defined service classes.