Order No. 164/16

ORDER IN RESPECT OF A REVIEW OF MANITOBA HYDRO'S COST OF SERVICE STUDY METHODOLOGY

December 20, 2016

BEFORE: Marilyn Kapitany, B.Sc. (Hon), M.Sc., Panel Chair
Hugh Grant, Ph.D., Member
Larry Ring, Q.C., Member

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1.0 Executive Summary

A Cost of Service Study ("COSS") is a method of apportioning a utility's costs among the various customers it serves. Manitoba Hydro is a utility that incurs costs to provide electricity service to its customers. Manitoba Hydro generates electricity, transmits the electricity over long distances to communities, distributes electricity within these communities to its customers, and provides other customer services.

Each Manitoba Hydro customer consumes power in varying amounts at different times of the day and in each season. Each customer is geographically in a unique location, with some customers densely grouped together in urban areas while others are dispersed through rural and remote areas. Customers who consume large amounts of electricity have different service requirements, such as voltage levels, than customers who consume less electricity. For rate-setting purposes, customers are grouped into customer classes according to their similar characteristics in terms of their electricity consumption and service requirements.

The objective in designing a COSS is to select a cost allocation method for the sharing of a utility's approved costs among the customer classes. Once the costs are allocated among the customer classes, the results may be used to set electricity rates for customers. While the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment. There is no single industry standard that applies to all COSS decisions.

By this Order, the Manitoba Public Utilities Board (Board)[1] reviews Manitoba Hydro's amended 2014 COSS Methodology and provides the Board's determination of the methodology to be utilized in preparing the COSS to be filed by Manitoba Hydro in conjunction with its next General Rate Application ("GRA") filing.

[1] Although Régis Gosselin, former Board Chair, and former Board member Richard Bel participated in aspects of this proceeding, neither took any part in the oral evidentiary hearing, Board deliberations, or this decision.

Principles Underlying the Present COSS

Manitoba Hydro incurs costs to provide service to its customers, but some customers "cause" more costs than others. Customers who do not use selected services and facilities of Manitoba Hydro do not cause Manitoba Hydro to incur the associated costs. For example, a large industrial customer may receive its power directly from the transmission system and therefore not need the services provided by the distribution system.

The Board accepts and applies the principle of cost causation in establishing the appropriate method of allocating Manitoba Hydro's financial costs to the various customer classes. The Board finds that other ratemaking principles for setting just and reasonable rates should be considered in a GRA, and not a cost of service process. A COSS neither determines nor changes rates, but may assist in rate setting and in evaluating whether customer classes pay their appropriate share of costs through rates. A COSS is normally filed with each GRA and, together with the proposed revenue requirement, rate design, and other pertinent information, forms the background supporting rate setting.

Key Issues

The COSS followed a sequential three-step process to:

- functionalize Manitoba Hydro's annual costs according to the five functions performed by the electrical system (Generation, Transmission, Subtransmission, Distribution, Customer Service);
- classify the functionalized costs into three classifications according to system design and operating characteristics that caused the costs to be incurred for Energy, Demand, Customer; and

- allocate the costs, which have been functionalized and classified, among Manitoba Hydro's customer classes.

In the course of this proceeding, the Board identified the following key issues in this COSS methodology review:

- The functionalization, classification, and allocation of generation and transmission assets, including the high voltage direct current ("HVDC") system and the U.S. interconnection, but excluding wind and coal assets;
- The treatment of export costs, including the number of export classes and the allocation of fixed and variable costs to such classes;
- The treatment and allocation of net export revenue; and
- The classification and allocation of demand-side management.

Board Findings

Generation Functionalized Costs

The Board finds that Manitoba Hydro's hydraulic and thermal generating stations should be functionalized as Generation.

Transmission that is necessary to connect generating stations to the networked transmission system, including the Northern Collector System and the northern converter stations, should also be functionalized as Generation. Power flows in only one direction on these lines, from the generating station to the networked transmission system, so this transmission is only used and useful as part of the generating station.

Bipoles I, II, and III should be functionalized as Generation as they connect northern generation with southern load centres, acting as extensions of the northern generating stations. The Board also finds that the high voltage direct current ("HVDC") facilities of the Riel and Dorsey Converter Stations should be functionalized as Generation. Bipole

III will function in the same manner as Bipoles I and II and, without northern generation, the HVDC portions of Dorsey and Riel have no use or function.

Classification of Generation Functionalized Costs

The Board finds that Generation costs should be classified as both Energy and Demand. The proportions of Energy and Demand should be determined by the system load factor method. The only exceptions to this approach are wind generation, water rentals, and variable hydraulic operation and maintenance costs which are to be classified as 100% Energy.

The reason for classifying Generation costs as both Demand and Energy is that Manitoba Hydro plans for and invests in assets to satisfy both peak demand and the energy requirements of Manitobans that must be met during drought conditions, when hydraulic generation is limited.

To determine the split between Demand and Energy classified costs, the Board directs the use of the system load factor as it is straightforward, is generally accepted in the industry, and has a clear basis in cost causation.

Allocation of the Generation Functionalized and Classified Costs

The Board finds that the Demand component of Generation costs should be allocated by the top 50 Winter Coincident Peak hours. Allocating Demand costs by Winter Coincident Peak reflects the shape of the domestic customer class loads during the high demand winter months in Manitoba.

The Energy component of Generation costs, as well as Generation costs that are classified as 100% Energy (i.e. wind purchases, water rentals, and variable hydraulic operating and maintenance costs) should be allocated to customer classes on the basis of customer class energy consumption (i.e. unweighted energy).

Transmission Functionalized Costs

The Board finds that the alternating current ("AC") transmission system operating at voltages greater than 100kV, the interprovincial interconnections, and the U.S. interconnections should be functionalized as Transmission. The costs of AC transmission are incurred to meet higher peak demand, maintain or enhance transmission network reliability, or geographically expand the AC network to serve additional load. The U.S. and interprovincial interconnections import and export energy and are sized for load rather than for generation output.

Classification and Allocation of Functionalized Transmission Costs

The Board finds that the costs of domestic AC and interprovincial transmission lines should be classified as 100% Demand and allocated on the basis of Winter Coincident Peak.

The U.S. interconnections should be classified on the basis of system load factor. The Demand portion should be allocated on the basis of Winter Coincident Peak and the Energy portion on the basis of unweighted energy.

Export Class and Export Revenues

The Board finds that an Export class should not be used in the COSS. The Board concludes that the Export class is not a vehicle for measuring the profitability of Manitoba Hydro's export business. A COSS does not measure any risks associated with the export venture, or the prudence of any resource development plans. The Export class is not like the domestic classes because export prices are determined either by markets or negotiated directly with export customers. Domestic customers, not export customers, are responsible for the costs of all of Manitoba Hydro's assets and operations.

The crediting of export revenue to the domestic classes should be based on each class's share of only Generation and Transmission costs. This approach is consistent with the principle of cost causation, as Manitoba Hydro's Generation and Transmission assets are the only functions utilized to effect export sales and thus the export revenues. Crediting export revenue on the basis of each class's share of Generation and Transmission costs is effectively equivalent to not having an Export class, making the Export class redundant.

Specific costs should be deducted from gross export revenues prior to the crediting of export revenues to the domestic classes. The costs to be deducted are water rentals, variable hydraulic operating and maintenance costs associated with exports, and the Affordable Energy Fund.

Demand-Side Management ("DSM")

The Board finds that DSM costs should be functionalized as 100% Generation. These costs should be classified the same way as other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion, and unweighted energy for the Energy portion.

DSM reduces overall domestic energy consumption, peak demand, or both. DSM is a system resource that avoids Generation costs.

Other Issues

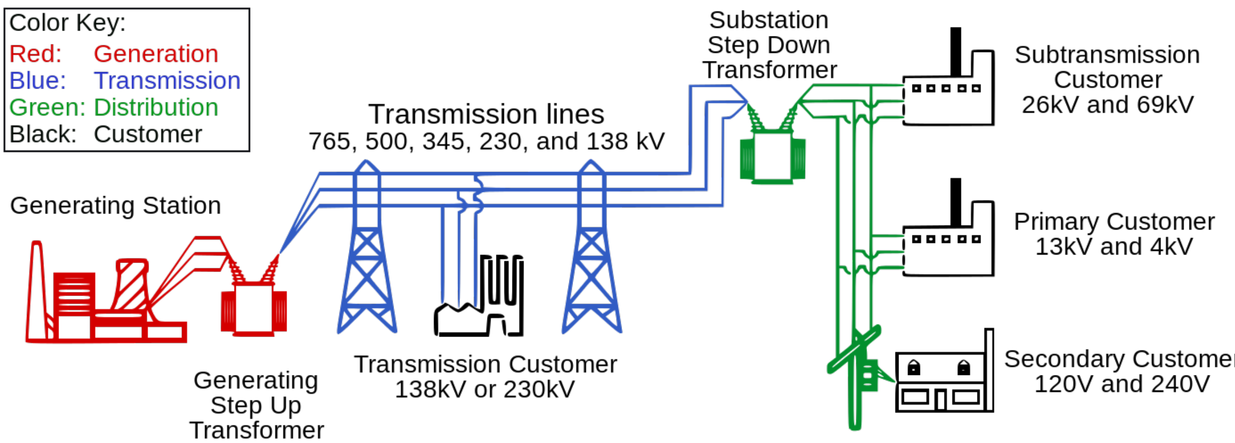
In this Order the Board also provides direction to Manitoba Hydro as to the methodology to be employed on other issues when preparing its next COSS to be filed in conjunction with its next GRA. Specifically, these other issues are Subtransmission, Distribution, Customer Services, and common costs, as well as the treatment of Late Payment Revenue and the Area and Roadway lighting customer class.

Compliance Filing

The Board directs Manitoba Hydro to provide a Compliance Filing which demonstrates the directives of the Board have been included in Manitoba Hydro's COSS model.

2.0 Description of an Electric Utility System

To provide background and context for the costs that are considered in a COSS, the following is a description of a generic electric utility system. Given the complex and technical nature of the electric utility system and the COSS methodology review process, a glossary of COSS terms and acronyms is included as Appendix A to this Order.



The above figure depicts a simple power system. The electric power system is a real-time energy delivery system, meaning there is limited storage available, so the amount of power generated must match the amount consumed at any given time. The system starts with generation, where electricity is produced at a power plant, which converts some form of primary energy – such as coal, natural gas, wind, or water – into electric power. Transmission lines connect generators to step-up transformers in utility substations, which increase the voltage of the power lines to be more suitable for efficient long-distance transportation. Transformers are devices which change the voltage of power lines. These lines and step-up transformers are called generation outlet transmission and are part of the generation function shown in red in the figure above.

The transmission lines (in blue in the above figure) represent the high-voltage, interconnected network of lines that transport the generated energy over long distances to the subtransmission and distribution systems, which are close to consumption locations. The transmission system is comprised of substations, transformers, switches to control the flow of electricity, towers, and wires. Subtransmission is similar to transmission in that it uses the same type of assets – towers, wires, substations, and transformers – but subtransmission equipment operates at a lower voltage than transmission equipment.

The final stages in the delivery of power to consumers are the subtransmission and distribution systems (in green and black in the above figure). These systems carry electricity from the transmission network to consumers. Step-down transformers reduce the voltage so electricity can be delivered safely to retail consumers. Retail consumers include homeowners, small and medium-sized businesses, and large industrial consumers. The subtransmission and distribution systems are designed in either a network configuration or in a radial configuration. A network configuration has several redundant paths for electricity to travel, such that the loss of one part of a transmission network does not result in the loss of electric service to consumers. A radial configuration does not have this redundancy. The combination of transmission, subtransmission, and distribution systems is also known as the electric grid.

The last component of the distribution system is the section that connects the electric grid with individual consumers. Consumers may connect with the grid at different voltages. Typically, large consumers, such as industry, are served at transmission or subtransmission-level voltages, medium consumers at primary voltages on the distribution system, and small commercial and residential consumers at secondary voltages. Consumers are connected to the distribution system through wires called service drops. Before the electricity is consumed by the end user's appliances, it is metered by electric meters, which are devices located near or on consumer premises.

An electric utility also performs other services in the course of delivering electricity. Utilities read meters, issue bills, provide energy efficiency programs called demand-side management, and provide other customer service functions.

The energy consumed at the end-user level is known as load. The load changes with time in response to changes in lighting levels, heating, air-conditioning and other power-consuming appliances and devices. The graph that represents load as function of time is called the load shape, and can be used to assess both average levels of demand and peak levels of demand on the system. Demand refers to the instantaneous load, while energy refers to load over a period of time.

A water supply analogy illustrates the difference between energy (total consumption) and demand (instantaneous peak requirement). A community is supplied with water over the year to meet its total consumption (energy). However, when there is a fire in the community and the fire department uses a significant amount of water, this would place an instantaneous peak requirement (demand) on the system for a short period of time.

3.0 Background on Manitoba Hydro's Cost of Service Study

The public hearing process that culminated with this Order represented the first review of Manitoba Hydro's Cost of Service Study ("COSS") methodology in a decade.

COSS is a method of allocating a utility's costs to the various customer classes it serves. Its purpose is to determine the allocation of the utility's approved costs, also known as its revenue requirement, among the customer classes. While there are many allocation methods, a COSS should allocate costs to customer classes on the basis of known customer characteristics such as service voltage and load shape.

By this Order, the Board directs Manitoba Hydro as to the methodology to be utilized in preparing its next COSS, which shall be filed with the Board in conjunction with Manitoba Hydro's next General Rate Application ("GRA"). The Board also directs Manitoba Hydro to provide a compliance filing to reflect the directives in this Order.

The Board's public hearing process, utilized in arriving at its findings and directives in this Order, is documented in the Board's procedural Orders 26/16 and 84/16 – both of which can be found on the Board's website at www.pub.gov.mb.ca. In brief summary, the procedural history included the identification of parties interested in the outcome of the COSS process (stakeholders, including interveners), the holding of stakeholder meetings prior to the filing of Manitoba Hydro's proposed COSS, written information requests, two facilitated workshops with the participation of the parties' experts, and two pre-hearing conferences. The second pre-hearing conference identified the following key issues:

- The functionalization, classification, and allocation of generation and transmission assets, including the high voltage direct current (HVDC) system and the U.S. interconnection, but excluding wind and coal assets;
- The treatment of export costs, including the number of export classes and the allocation of fixed and variable costs to such classes;

- The treatment and allocation of Net Export Revenue; and

- The classification and allocation of demand-side management.

These key issues were not only the subject of written evidence, but also the oral evidentiary portion of the hearing. The latter was structured as a concurrent evidence session of the interveners' experts following the testimony of Manitoba Hydro.

In addition to written pre-filed evidence from the parties, there were submissions on issues that were not part of the oral hearing, as well as submissions following the oral hearings on the identified key issues.

A prospective cost of service study ("PCOSS") is based on a year with forecast costs and revenues, as opposed to historical costs and revenues. Manitoba Hydro's 2014 Prospective Cost of Service Study ("PCOSS14") was used as the basis of this proceeding due to the familiarity of many of the parties and expert witnesses with this forecast year. The costs in PCOSS14 were those that Manitoba Hydro forecast in its 2012 Integrated Financial Forecast for the 2013/14 fiscal year. The updated PCOSS14 Amended is also based on the 2013/14 fiscal year costs and revenues but has some methodology changes compared to PCOSS14.

This Order and the directives in it follow the Board's review of all evidence, submissions, and the Board's deliberations on the issues. The Board thanks the parties and their witnesses for their assistance throughout this process.

4.0 The Ratemaking Process

The Board's process for establishing electricity rates for Manitobans follows three sequential steps:

1. Determination of Manitoba Hydro's approved Revenue Requirement reflecting all the Board-approved costs incurred to provide services to all its customers;

2. Determination of a Board-approved COSS for Manitoba Hydro – The COSS allocates Manitoba Hydro's overall Revenue Requirement to each customer class based on cost causation principles. Cost causation refers to a determination of what or who is causing costs to be incurred by Manitoba Hydro, to the extent practical;

3. Determination of a Board-approved Rate Design – This process establishes the rates Manitoba Hydro is permitted to charge each customer class in order to collect the target revenue from each class. In the rate design step, rates for kilowatt-hour (kWh) energy consumption, kilowatt (kW) demand, and basic monthly charges are set for customer classes.

This Order addresses only the second of the above three steps. It provides Manitoba Hydro with a Board-approved COSS methodology to be utilized in Manitoba Hydro's filings before the Board when Manitoba Hydro files a General Rate Application ("GRA") requesting changes in domestic rates.

This Order does not establish Manitoba Hydro's Revenue Requirement or rates for domestic or export customers. Domestic rates are established through a GRA where the Board approves Manitoba Hydro's Revenue Requirement. Using the tools available to the Board, including the approved COSS, the Board then reviews and approves Manitoba Hydro's rate design and establishes the resulting rates. In setting domestic electricity rates, the Board has discretion as to what, if any, use is made of the COSS. As noted in *Consumers' Association of Canada (Man) Inc et al v Manitoba Hydro*

Electric Board (2005), 195 Man R (2nd) 12 in the submissions of Manitoba Hydro and the Board:

> *… There is no basis in the legislation to support the argument that the Board is required to focus on pure cost causation in approving a fair rate, or that a particular tool or methodology, notably the COSS, must be used in order to fairly allocate costs amongst customer classes*

And:

> *…Hydro then goes on to argue, as did the PUB, that there is no requirement for the PUB to rely on a COSS to fix a just and reasonable rate, and that such a study is but one of the elements that the PUB could or could not rely upon in arriving at its order.*

In the decision, and on the issue of the use of the COSS, the Manitoba Court of Appeal determined:

> *A review of the record demonstrates that the PUB did in fact review extensive financial information and then exercised its discretion. It may well be that the PUB could not, or would not, review the specific financial tools that the applicants argue it should have, but that is insufficient in my mind to justify a finding that, as a whole, the PUB did not fix rates that were just and reasonable.*

In contrast to the process for domestic rates, export prices for Manitoba Hydro's electricity are set either by a competitive market or through direct negotiation with utilities in other jurisdictions and so are not approved by the Board when approving domestic rates.

Purpose of a Cost of Service Study (COSS)

A COSS is a method of apportioning a utility's costs among the various classes of customers it serves. The purpose of a COSS is to allocate the utility's Board-approved revenue requirement among the customer classes.

Each customer consumes power in varying amounts at different times of the day and in each season. Some customers are densely grouped together in urban areas while others are dispersed through rural and remote areas. Customers who consume large amounts of electricity have different service requirements, such as voltage, than customers who consume less electricity. For rate-setting purposes, customers are grouped into customer classes according to their similar characteristics in terms of their electricity consumption and service requirements.

In providing electricity service to its customers, a utility like Manitoba Hydro incurs costs to generate electricity, to transmit the electricity over long distances to communities, to distribute electricity within these communities, and to provide customer services such as billing.

The objective in designing a COSS is to select a cost allocation method for sharing of costs. A COSS neither determines nor changes rates but may assist in rate setting by evaluating whether customer classes pay their appropriate share of costs through rates.

While the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment. Because each utility is unique, with data limitations and multiple economic alternatives, there is no one industry standard that applies to all COSS decisions.

As explained by Manitoba Hydro, its COSS is an 'embedded cost study', which is distinct from a COSS based on 'marginal costs'. Embedded cost analyses differ from marginal cost analyses in two important ways. First, embedded cost analyses are backward looking and consider the costs of the utility's plant that is already in service. Marginal cost analyses are forward looking and consider the cost of plant to be added in the future. Second, embedded cost studies are always based on revenue requirement analyses that examine average costs, whereas marginal costs refer to the cost of adding an incremental amount of load to a utility system.

Manitoba Hydro’s embedded COSS is based on a financial forecast of costs for a single year from Manitoba Hydro’s Integrated Financial Forecast. That is, the costs allocated through the COSS are those that make up Manitoba Hydro’s Board-approved Revenue Requirement for the year selected. Manitoba Hydro utilizes plant investment (original investment costs plus plant additions net of accumulated depreciation and contributions) for purposes of allocating revenue requirement items such as finance expense, depreciation and amortization, capital and other taxes, and net income. Operating, Maintenance and Administrative expense is forecast by facility or service so it can be appropriately allocated amongst the customer classes.

Cost of Service Study Process

The overall COSS process starts with a Board-approved Revenue Requirement for Manitoba Hydro. For purposes of the Board’s and Parties’ review of Manitoba Hydro’s COSS methodology, the assumed Revenue Requirement is $1.75 billion based on 2013/14 fiscal year. The costs that make up that $1.75 billion Revenue Requirement are then systematically studied in the various COSS steps.

A Cost of Service Study follows three sequential steps:

1. Functionalization – Manitoba Hydro’s $1.75 billion of costs are grouped initially according to the five functions performed by the electrical system:
   - Customer Services – the costs incurred to provide such services as call centre services and billing;
   - Distribution – includes the costs of the lower voltage wires and transformers directly serving individual or groups of customers, including the service drop wires to the business or dwelling, and the meters;
   - Subtransmission – includes higher level voltage wires and transformers carrying electricity to some portions of the distribution system;

– Transmission (including Ancillary Services) – the highest voltage network of wires carrying electric power longer distances and also to connection points with the subtransmission and distribution systems; and

– Generation – includes the facilities that create electricity powered by water, wind, or fossil fuels and the wires directly associated with connecting the generator to the transmission system.

The functionalization process determines which of the above five functions are used to provide service to each customer class. Some facilities are relatively straightforward to functionalize but others serve multiple purposes and provide a broad array of benefits. Such assets make the functionalization process more complex.

2. Classification – Functionalized costs are classified according to system design and operating characteristics that cause the costs to be incurred. The three classifications used in relation to Manitoba Hydro's functionalized costs are:

   – Energy – for costs that vary with the total consumption of electricity;

   – Demand – for costs that vary with consumption of electricity at periods of peak demand, which tend to be costs for facilities that must be "sized" (have adequate capacity) to serve those demands;

   – Customer – for costs that vary with the number of customers Manitoba Hydro serves.

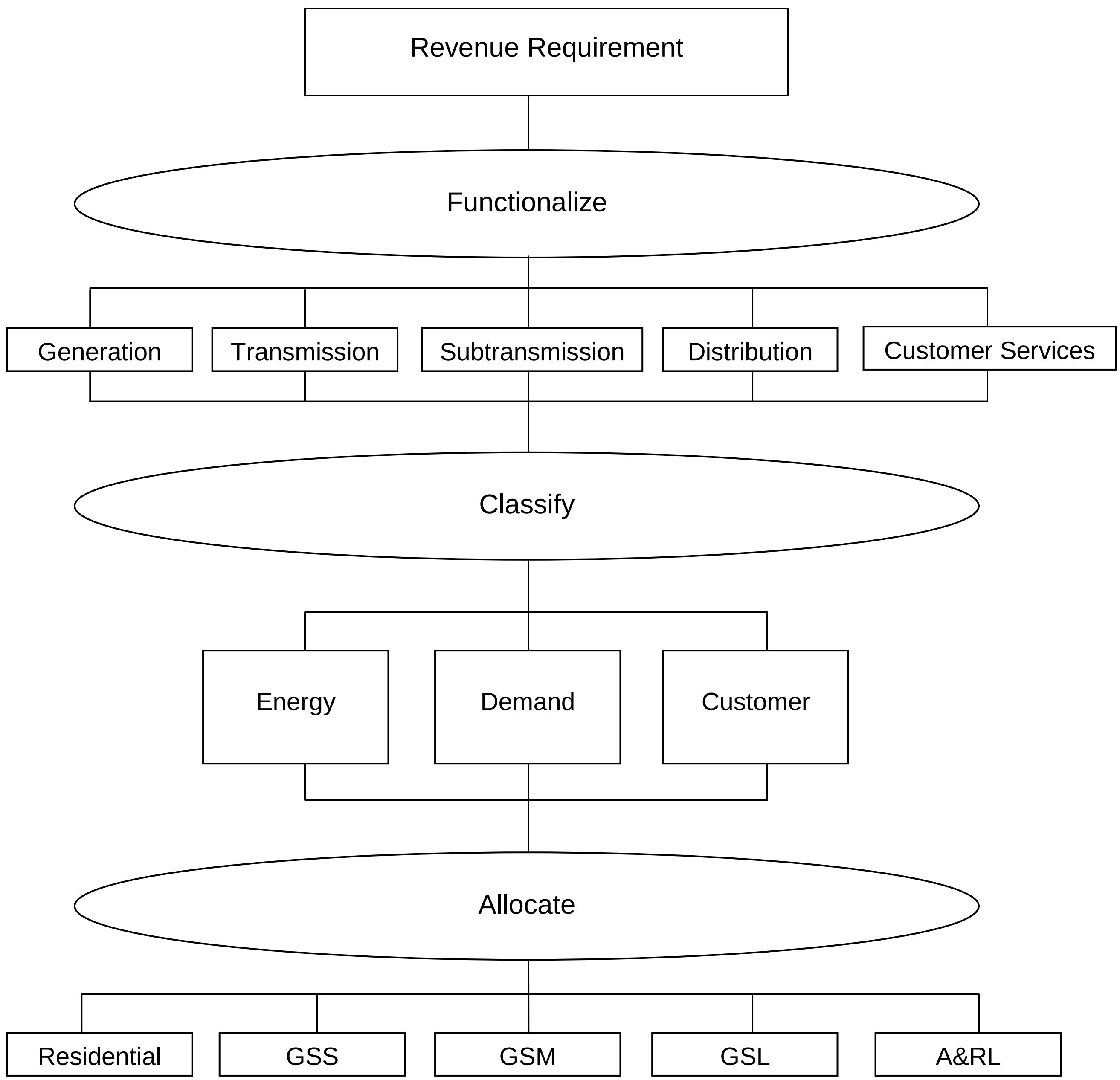
The classification of costs as Energy, Demand, and Customer-related is widespread throughout the electric utility industry.

3. Allocation – The costs that have been functionalized and classified are then allocated among Manitoba Hydro's customer classes. Typically, Demand-related costs are allocated based on the class's proportional share of demand during

some peak period. Energy-related costs are typically allocated based on the consumption of energy over the course of the year. Customer-related costs are typically allocated based on the number of customers in each customer class.

The allocation process also considers which customer classes use specific functions, and then allocates the costs of those functions to those customer classes only. As an example, customers taking service directly from the transmission system do not use the utility distribution system, and are therefore not allocated the costs of the distribution system.

The functionalization, classification, and allocation process is illustrated in the following flow chart.



Schematic of the Functionalization, Classification, and Allocation Process

The following customer classes are included in Manitoba Hydro's Cost of Service Study. These customer classes are defined in the Glossary appended to this Order:

- Residential
- General Service - Small ("GSS")
- General Service - Medium ("GSM")
- General Service – Large ("GSL") 0-30kV
- General Service - Large 30-100kV
- General Service - Large >100kV
- Area and Roadway Lighting
- Export
- Diesel[2]

One of the outputs of a COSS is the calculation of total costs allocated to each customer class. The COSS output is a tool that can be used in the ratemaking process to assign target revenue for each rate class. This step includes comparisons showing scenarios of target class revenue to the cost of service-based costs allocated to the respective class. The ratio of the target revenues by class to the allocated class costs results in a Revenue to Cost Coverage ratio ("RCC"). A RCC ratio less than unity (1.0) means that the revenue generated by a class is not sufficient to recover all the costs allocated and assigned to that class; conversely a RCC ratio greater than unity (1.0) means that Manitoba Hydro is recovering more revenue from that class than its allocated and assigned costs.

[2] Most of Manitoba Hydro's customers are served by its hydraulic generation assets and high-voltage transmission network. Customers in four northern remote communities (Shamattawa, Brochet, Lac Brochet, and Tadoule Lake) are not connected to Manitoba Hydro's transmission grid and are served by local diesel-fuelled generators. These four communities are referred to as the "Diesel Zone". Manitoba Hydro develops a separate and distinct COSS for its Diesel Zone customers. Manitoba Hydro tracks all Diesel Zone costs separately from other costs, and then directly assigns such costs to the Diesel class in its COSS. The Diesel COSS then determines the costs that are allocated to the different customer classes within the Diesel Zone. The Diesel COSS methodology is not the subject of this Order.

As previously noted, while a COSS appears to be arithmetically exact, it involves a number of decisions that require the application of judgment. Because of this, and to address goals of gradualism in the ratemaking process, many utilities do not set rates such that the RCC ratios are exactly unity. Instead, many utilities and their regulators, including Manitoba Hydro and the Board, recognize a zone of reasonableness within which the utility is to target the RCC ratios of its customer classes. Manitoba Hydro's zone of reasonableness is currently 0.95 to 1.05, meaning that Manitoba Hydro considers it reasonable when a customer class's rates are set to recover between 95% and 105% of the costs allocated to that class in the COSS. RCCs and the zone of reasonableness are rate design issues that are addressed in the context of a GRA.

5.0 Principles Applicable to the Cost of Service Study ("COSS") Review

COSS Goals and Principles

There was general consensus in this proceeding that cost causation should underpin the COSS methodology because customers should pay for the facilities and services they use. There were divergent views as to the meaning of cost causation. Determining how customers cause utility costs to be incurred is informed by how the system is planned as well as how it is used. For example, cost causation could consider a utility's most recent planning studies or the planning done to justify assets when originally placed in service. Additionally, cost causation could consider solely the primary benefit of a given asset, or all the benefits, even if all the benefits were not necessary to justify purchasing, retaining, or building the asset. Cost causation could focus on a range of historical conditions or a single forecast condition to assess an asset's use and benefits to the system.

There were also divergent views in this proceeding as to which principles should be used in developing a COSS. One view is to focus solely on cost causation in the COSS methodology, applying other principles only at the rate design step of ratemaking. The other view is to consider cost causation along with fairness, equity, and other ratemaking goals when developing a COSS methodology.

Manitoba Hydro's Position

Manitoba Hydro indicates that, while there is no one right or wrong COSS methodology, it takes into consideration fairness, equity and other ratemaking goals when looking at the issue of cost causation, instead of taking a pure and narrow approach to cost causation. The Revenue to Cost Coverage ("RCC") ratios that result from the COSS also influence Manitoba Hydro's overall cost of service methodology.

Manitoba Hydro incorporates its ratemaking goals when developing its COSS methodology. Manitoba Hydro's ratemaking goals can be summarized to include:

- Recovery of Revenue Requirement – the approved rates should provide Manitoba Hydro with the opportunity to recover its approved revenue requirement.
- Fairness and Equity – costs are equitably shared if they are based on cost causation, but cost causation may not be the only consideration in cost allocation.
- Rate Stability and Gradualism – changes to the COSS methodology should not adversely affect rate stability.
- Efficiency – in this context, efficiency means providing appropriate price signals to customers of the cost of energy. Manitoba Hydro incorporates efficiency in its COSS by incorporating marginal costs in its allocation methods.
- Competitiveness of Rates – Manitoba Hydro has a goal to maintain rates that are competitive compared to other Canadian electric utilities.
- Simplicity – the COSS methodology should balance complexity with the benefits and costs of executing the methodology.

Intervener Positions

The Consumers Coalition ("the Coalition") recommends including broader policy considerations in the COSS process, as reflected in the legislation governing the Board's authority over rate setting. In contrast, Green Action Centre ("GAC") and the Manitoba Industrial Power Users Group ("MIPUG") advocate for a stricter, cost-causal approach to developing a COSS methodology. GAC and MIPUG argue that the balancing of cost causation with other considerations should be done in the rate setting stage of a General Rate Application ("GRA"). GAC characterizes Manitoba Hydro's approach to its COSS methodology as being inappropriately driven by RCC results and that Manitoba Hydro rejects changes that it deems to have too small or too large of an impact. The General Service Small/General Service Medium representative

(“GSS/GSM”) suggests that a foundational set of principles is needed to inform cost allocation, which in turn informs the next step of the ratemaking process which is rate design.

Board Findings

The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage.

The Board finds that Manitoba Hydro’s ratemaking principles and goals of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a General Rate Application (“GRA”) and not in the cost of service methodology. While ratemaking principles are important in the overall process of setting rates, these concepts are issues for rate design and should therefore not be considered at the COSS stage. Likewise, consideration of RCC ratios is a rate design matter that should be addressed in the rate-setting phase of a GRA.

Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro’s current system planning, as well as the current use. This methodology is to apply to assets currently in service, as well as future assets, such as Keeyask and Bipole III.

The Board also finds that cost causation requires consideration of all the uses and benefits of an asset, to recognize that both primary and secondary benefits influence the planning and justification of assets. These considerations should be assessed over a range of years (as opposed to a single forecasted year) and over a range of conditions in order to capture all of the uses and benefits of an asset in determining cost causation.

The Board finds that, as acknowledged by Manitoba Hydro, it is not bound by prior Board decisions. As such, the Board has approached this review of Manitoba Hydro’s

COSS methodology through applying the principles discussed above to the evidence in the present proceeding.

Marginal Cost of Service Studies

During the hearing, the topic of a COSS based on marginal costs, rather than embedded costs, was raised. Marginal cost is the cost to serve an additional unit; it has little relation to embedded costs.

Manitoba Hydro's Position

Manitoba Hydro prepares its COSS using embedded costs. Manitoba Hydro incorporates short-run marginal cost information in its embedded COSS methodology through its Weighted Energy allocator, in order to assign greater cost responsibility to classes that consume more energy during peak periods.

Intervener Positions

The Coalition submits that a marginal COSS can provide insight into the allocation of Net Export Revenues, the appropriate zone of reasonableness, and whether rates are just and reasonable. It recommends that the Board direct Manitoba Hydro to consult with interveners and file a marginal COSS by October 1, 2017.

MIPUG disagrees with the need for a marginal COSS, suggesting it is unneeded and would result in an excessive delay in achieving a final, Board-approved COSS methodology.

Board Findings

The Board finds that the COSS performed by Manitoba Hydro is to be an embedded COSS. Although discussion of a marginal COSS was introduced during the oral hearing portion of this proceeding and is recommended by the Coalition, the Board finds that there is insufficient evidence on the record to support the development of a marginal COSS. In addition, the Board notes that marginal COSSs are rare in other jurisdictions.

The Board is satisfied that Manitoba Hydro has addressed previous Board directives related to marginal cost from Orders 117/06, 116/08, and 150/08. The Board rejects the Coalition’s request for the Board to direct Manitoba Hydro to take further steps towards preparing a marginal COSS.

6.0 The Treatment of Export Revenue

Manitoba Hydro plans its system so that it meets two planning criteria: (1) having sufficient generation under minimum, or what is referred to as dependable, water flows, and (2) having sufficient generation to meet the maximum winter peak demand. Because the dependable flow condition is based on the worst drought conditions in Manitoba Hydro's one hundred year hydrological record, in water years with more water than such extreme drought, there is surplus generation available that may be exported. Manitoba Hydro also must have sufficient generation capacity to meet Manitoba Hydro's customers' peak electricity demands plus an operating reserve margin. Hydroelectric generating stations are built with substantial capacity such that large amounts of generation, with long lead times, are added to Manitoba Hydro's system in large increments resulting in surplus generation even under dependable flow conditions. The combination of these effects means Manitoba Hydro has surplus generation that can be exported to earn additional revenue.

Manitoba Hydro's COSS is based on the median flow of the 100-year hydrological record. In a median flow year, there is substantial energy that may be exported, since median flows result in approximately 40% more hydraulic generation than dependable flows. These export sales result in revenue, which Manitoba Hydro forecasts in PCOSS14 Amended to be $345 million. One of the issues in this COSS proceeding was determining the appropriate treatment of these export revenues, and how these revenues should benefit domestic ratepayers.

Existence of an Export Class

The original reasons for a separate Export class were discussed in a 1988 report from the Board to the Minister[3]. In this report, the Board recommended that revenues and costs related to export sales be segregated in Manitoba Hydro's accounting records in

[3] Board Report to the Minister of Energy and Mines, March 31, 1988.

order to demonstrate that domestic customers are not subsidizing export sales. To accomplish this, the Board suggested the method of treating export sales as a separate customer class in the COSS. In addition, Manitoba Hydro has explained that the creation of an Export class was to promote fairness, including a means of returning export revenues to domestic customers on a basis that Manitoba Hydro considered to be fairer.

Manitoba Hydro's Position

Manitoba Hydro uses an Export class as a mechanism to share export revenues among domestic customer classes. Manitoba Hydro suggests this goal is accomplished by sharing export revenues on each class's share of total allocated costs or of total costs, compared with the prior approach of returning export revenue on the basis of a customer class's share of Generation and Transmission costs only. The purpose of the Export class in the COSS is not to judge the profitability of exports or past investment decisions.

Manitoba Hydro notes that all experts in this proceeding viewed an Export class as appropriate. In Manitoba Hydro's view, elimination of the Export class does not eliminate the issue of the appropriate share of the costs that exports are to bear and may treat export revenues in a less transparent fashion. Nevertheless, Manitoba Hydro also accepts that, where low prices for opportunity sales exist and export revenues are constrained, the "No Export class" option may be a reasonable cost of service approach. Manitoba Hydro argues that when there are significant export sales and no export class, there is a risk of providing excessive subsidies to domestic classes.

Intervener Positions

The Coalition supports continuing the Export class as a matter of fairness in allocating costs. While the Coalition suggests that the "No Export class" approach is simpler, it argues that there are three main reasons for maintaining an Export class: (1) Manitoba Hydro's connection to the U.S. marketplace and the role of export sales in its revenues, (2) evidence that suggests that export revenues may grow, and (3) an Export class provides a transparent and evidence-based mechanism in which to discuss the implications for fairness and equity between classes.

While GAC did not take an explicit position, its submissions appear to support continuing the use of an Export class. The City of Winnipeg also did not take a position on the existence of an Export class in its final argument, but its expert witness agreed with Manitoba Hydro that an Export class is used to achieve greater fairness and is a reasonable and transparent mechanism for sharing export revenues among the domestic classes.

Although MIPUG also did not take a position on the existence of an Export class in its final argument, its expert witness suggested that the Board should consider eliminating the Export class and that the issues in this proceeding could be simplified as a result.

The experts and parties in this proceeding agree that the use of an Export class is not an appropriate way to measure or determine whether Manitoba Hydro’s decisions to proceed with particular capital projects were economically sound.

Board Findings

The Board finds that an Export class should not be used in the COSS.

First, the Board notes the general agreement of the experts and parties in this proceeding that the use of an Export class is not an appropriate way to measure or determine whether Manitoba Hydro’s decisions to proceed with particular capital projects were economically sound. The Board concludes that the Export class is not a vehicle for measuring the profitability of Manitoba Hydro’s export business, nor is it possible to use the COSS to measure risks associated with the export venture or the prudence of any resource development plans.

Second, the Board determines that, in part, the creation of the Export class was based on ratemaking goals and not cost of service principles. As discussed above, Manitoba Hydro’s purpose for including an Export class in the COSS is to achieve fairness and equity between the rates paid by domestic customer classes. The Board's view is that these concerns are more appropriately considered and, if necessary, addressed in the context of ratemaking in a GRA.

Third, the nature of Manitoba Hydro's export business is such that the prices paid by export customers are not based on costs allocated to the Export class. The Export class is not like the domestic classes because export prices are determined either by markets or negotiated directly with export customers. Consequently, export customers do not pay rates that are regulated on a cost of service basis.

Fourth, as explained in the next section of this Order, the Board finds that the crediting of export revenue to the domestic classes should be based on each class's share of only Generation and Transmission costs. This method of crediting export revenue supports the decision to eliminate the Export class. As acknowledged by Manitoba Hydro as well as the expert witnesses for MIPUG and GAC, crediting export revenue on the basis of Generation and Transmission is effectively equivalent to not having an Export class, making the Export class redundant.

If an Export class was to be maintained, the domestic classes' Generation and Transmission costs would be reduced by the amount of costs allocated to the Export class. Correspondingly, export revenue credited to domestic classes would be reduced by a roughly equivalent amount. Because the allocation of costs and the crediting of export revenues are both done on the same basis, the resulting class costs would be effectively equivalent to having no Export class.

Fifth, eliminating the Export class improves transparency in the COSS by showing that domestic customers are ultimately responsible for all of Manitoba Hydro's costs. Allocating costs to an Export class gives the false appearance of eliminating the responsibility of domestic customers for those costs. However, for every dollar assigned to an Export class, there is an equivalent reduction to revenue credited to domestic customers. As a consequence, the aggregate cost responsibility of domestic customers is unchanged.

The Crediting of Export Revenue

Prior to 2005, Manitoba Hydro credited export revenue against a customer class's responsibility for Generation and Transmission costs only. It was the position of the Board that, because export revenues arose from generation and transmission capacity, the export revenues derived from that capacity were credited in proportion to class responsibility for generation and transmission costs.

However, since that time, the approach to the treatment of export revenue has been to first calculate Net Export Revenue ("NER") and then credit NER on the basis of each class's share of total allocated costs, which includes Generation, Transmission, Subtransmission, Distribution, and Customer Services costs. NER is calculated as the revenue arising from export sales, less costs directly assigned and allocated to the Export class within the COSS.

Manitoba Hydro Position

Manitoba Hydro allocates and assigns Generation and Transmission costs to an Export customer class, analogous to allocation and assignment to domestic customer classes. The Export class costs are deducted from gross export revenues to determine NER. Export revenues reduce the costs allocated to domestic classes in two ways: the domestic class responsibility for Generation and Transmission costs is reduced as these costs are allocated (or directly assigned) to the Export class, and the NER is credited to the domestic classes to further lower their share of the overall revenue requirement.

In the course of this proceeding, Manitoba Hydro updated its recommendation for the treatment of NER to extend the crediting of export revenue to include total allocated costs plus all costs directly assigned to specific customer classes ("total costs").

Manitoba Hydro submits that crediting NER based on total costs is a more fair and equitable approach than crediting NER based on Generation and Transmission costs alone, and mitigates over-subsidization to some customer classes. In Manitoba Hydro's perspective, the past approach of crediting export revenue on the basis of class shares of Generation and Transmission costs resulted in some customer classes, for whom those Generation and Transmission costs represented a greater portion of their costs, benefitting to a greater degree than other customer classes that make greater use of the distribution system. When market conditions were favourable for high export revenues, this led to what Manitoba Hydro has characterized as distorted RCC ratios and an unfair allocation of costs.

Manitoba Hydro states that exports are made possible not only by Generation and Transmission assets, but also because of freed up surplus energy and capacity that result from periods of low usage on the distribution system.

Manitoba Hydro's view is that crediting NER based on total costs reduces the impact of oscillations in export revenue over time, including as a result of changing market conditions, which in turn reduces volatility in RCC ratios.

Intervener Positions

The Coalition supports crediting NER on the basis of total allocated costs, the treatment of NER initially proposed by Manitoba Hydro. The Coalition's view is that, consistent with the Board's statutory role of approving just and reasonable consumer rates, crediting of NER on total allocated costs is more just and equitable than allocation of NER on only Generation and Transmission costs. In the past, the latter approach gave rise to problematic results when export prices exceeded domestic rates. If one domestic customer class increased its load, there would be less electricity available for export. As a result, Manitoba Hydro's overall revenues would decline. The additional costs would be borne by all domestic customer classes, but these costs would be disproportionately allocated to classes other than the class that increased its load. The Coalition submits that this result is not consistent with cost causation.

The Coalition argues that some directly assigned costs, such as street light luminaires, should not be included in the allocation base for NER as these assets are not an integral part of Manitoba Hydro's obligation to serve.

The positions of GSS/GSM and the City of Winnipeg are that NER should be credited on the basis of a class's share of total costs. Manitoba Hydro changed its final proposed methodology of crediting NER to align with GSS/GSM's and the City of Winnipeg's proposed methodology. These interveners and Manitoba Hydro agree that this approach minimizes unfair crediting of NER and results in a more equitable allocation process.

GAC supports crediting NER on the basis of total costs as a matter of fairness, and recommends including directly assigned costs in the calculation of the NER credit, but excluding directly assigned dedicated end-use facilities such as street lighting.

MIPUG departs from the other interveners and recommends that NER be excluded from the COSS, arguing that this approach is consistent with maintaining a principled COSS study and avoids class-specific advocacy. MIPUG's view is that NER is not a cost, but rather is revenue that is not inherently linked to embedded costs. MIPUG recommends that RCC ratios for the domestic classes absent any NER credit can be used to set rates. Over time, once the RCC ratios are brought closer to unity, then there are other possible options for the treatment of NER if it is excluded from the COSS, but MIPUG submits that these issues do not need to be resolved at this time.

MIPUG's alternative position is that if NER is included in the COSS, it should be credited against Generation and Transmission costs only as those are the assets that give rise to the export revenue.

Board Findings

The Board finds that export revenue should be credited to the domestic classes based only on each class's share of total Generation and Transmission costs. This approach is consistent with the principle of cost causation as Manitoba Hydro's Generation and

Transmission assets are the only functions utilized to effect export sales and thus export revenues. The Board finds that the Distribution system is not utilized to effect export sales.

The Board finds that there is no cost of service reason to credit export revenue on a basis that includes Subtransmission, Distribution, and Customer Service. Manitoba Hydro's crediting of export revenue on total costs is based on Manitoba Hydro's approach of integrating ratemaking goals into the COSS. As the Board has stated above, those goals are to be considered at the final ratemaking stage.

Manitoba Hydro asserts that export sales are made possible by freed up energy and capacity occurring at times of low use on the Distribution system, and that this justifies crediting export revenues on a basis that includes Distribution costs in addition to Generation and Transmission. In response to this, the Board-approved methodology for the allocation of Generation and Transmission costs already recognizes the fact that a large portion of the energy that is available for exports results from lower domestic customer use of Generation and Transmission costs in certain seasons or hours. The Board-approved methodology specifies that the largest portion of Generation costs is allocated on an Energy basis, which recognizes the lower use in certain seasons or hours. Manitoba Hydro's argument focuses on the fact that the lower loads of the Distribution-connected classes create the export opportunity, when in fact the lower loads have already been recognized through the lower allocation of the costs with the Energy classification.

It does not logically follow that, because periods of low demand on the distribution system create opportunities to export, Distribution costs should be part of the basis for crediting export revenues. Regardless of the variation in distribution system load, Distribution costs – that is the costs of distribution substations, transformers, poles, wires, meters, and services – do not vary with export load. There is no cost causation basis for crediting export revenues to defray these costs, which are solely a function of maximum class demand and number of customers on Manitoba Hydro's system.

The Board finds that the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets. To use Distribution costs to credit export revenue of any kind would be a disconnection to cost causation and thus inappropriate.

The Board concludes that export revenues are not a “dividend” that can be assigned or based on considerations other than cost causation. Cost causation of export revenues was illustrated in the Board’s 2014 review of the Keeyask and Conawapa generating station projects as part of the Needs For and Alternatives To (“NFAT”) review. Manitoba Hydro’s economic justification for these projects and the Board’s NFAT recommendations were based on using the full quantum of export revenues to lower the cost of the new Generation and Transmission assets. Distribution costs were not relevant in the justification of the NFAT’s economic case. The eventual benefits that are to flow to Manitoba Hydro’s customers from the recommended NFAT development plan are appropriately shared among the domestic classes if they are shared on the same basis as the costs are apportioned. Crediting export revenues on a basis other than Generation and Transmission misdirects benefits to some domestic classes at the expense of others. This further affirms the rationale for crediting export revenues on the basis of Generation and Transmission costs allocated to domestic classes.

If the COSS methodology is driven by considerations other than cost causation, then the final results of the COSS are muddled. Allocation of NER based on Generation, Transmission, and Distribution results in an increased subsidy to Distribution-connected customer classes (such as Residential and GSS). When considering the RCC ratios in a GRA, the true ratios are skewed because of the NER subsidy. Subsidies within the COSS are challenging to disentangle at the ratemaking stage. The Board is of the view that additional transparency is achieved with the COSS and the ratemaking process if these implicit or explicit subsidies are eliminated from the COSS.

Costs Deducted From Export Revenues

Manitoba Hydro's PCOSS14 Amended uses an Export class, to which Manitoba Hydro directly assigns and allocates costs in a conceptually similar process as assignments and allocations to domestic customer classes. Costs that are attributable to making export sales are assigned and allocated to the Export class. For example, portions of Generation and Transmission costs are allocated to the Export class. Other specific examples include:

- portions of Midcontinent Independent System Operator ("MISO") fees, which Manitoba Hydro pays to participate in the MISO market,

- National Energy Board ("NEB") fees, which Manitoba Hydro pays to secure permits to import and export electricity to the U.S., and

- the incremental costs of additional exported electricity, such as water rental charges. For each additional kilowatt-hour of electricity that Manitoba Hydro generates, it pays to the Province a water rental fee. If the additional kilowatt-hour of electricity is exported, this water rental fee is directly attributable to making that export sale.

In addition, Manitoba Hydro directly assigns certain policy "costs" to the Export class.

One such policy charge is called the Uniform Rate Adjustment ("URA"). Prior to uniform rates, Manitoba Hydro charged higher rates to customers in lower-population density regions of the Province. With the introduction of uniform rates by way of legislation in November 2001, rate zone distinctions for customers on the interconnected grid were eliminated and all rates in the previous zones 2 and 3 were reduced to be the same as the rate charged in zone 1, which includes the City of Winnipeg. The financial impact of uniform rates was a decrease in Manitoba Hydro's revenues of approximately $14.8 million in 2003, the first full year of implementation. Manitoba Hydro has escalated the adjustment since then based on the Board-approved rate increases. The financial impact of uniform rates in PCOSS14 Amended is $23.5 million. Manitoba Hydro reduces the responsibility of the Residential, General Service Small ("GSS"), and General Service Medium ("GSM") classes for this revenue through the URA. Manitoba Hydro charges the URA to the Export class, such that it appears as a "cost" to the Export class.

Another policy charge to the Export class made by Manitoba Hydro in PCOSS14 Amended is the cost of the Affordable Energy Fund ("AEF"). In accordance with the provisions of *The Energy Savings Act*, SM 2012, c 26 and its predecessor legislation, *The Winter Heating Cost Control Act*, CCSM c W165, Manitoba Hydro established an Affordable Energy Fund in the initial amount of $35 million for the purpose of providing support for energy efficiency and alternative energy programs and services. In PCOSS14 Amended, the cost of the AEF charged to the Export class is $12.8 million.

The elimination of the Export class makes it unnecessary to determine the allocation of costs to the Export class. However, there are some costs, directly linked to exports, that could be appropriately deducted from the gross export revenues prior to the crediting of export revenues to the domestic classes.

Board Findings

The Board finds that the energy costs for water rentals and variable hydraulic operating and maintenance costs associated with exports should be deducted from gross export revenues. This would be the portion of those cost categories that is represented by the volume of export sales. The Board is not ordering all water rental costs to be deducted from gross export revenues, but rather the water rental cost per kilowatt-hour multiplied by the kilowatt-hours of export sales. The same process is to be applied to subtract a portion of the variable operating and maintenance costs from gross export revenues. The total costs of the AEF should also be deducted from the gross export revenues. The Board does not accept that any other specific costs should be deducted from export revenue, including the costs of the URA.

With respect to water rentals and variable hydraulic operating and maintenance costs, the Board finds that these specific costs are incremental costs directly attributable to energy that is exported. Put another way, for every additional kilowatt-hour of energy exported, additional cost is incurred. There is therefore a cost causation basis for deducting these costs from export revenues.

The Board also finds that the costs of the AEF should be deducted from export revenues. *The Energy Savings Act* and *The Winter Heating Cost Control Act* provide that the costs associated with the AEF are to be paid for by export revenues. While the legislation requires the AEF to be established from export revenues, the Board notes that export revenues do not in actuality pay for those costs as export prices are determined by the MISO market and bilateral contract negotiations. Therefore, the costs of the AEF are borne by the domestic customer classes, as the amount of the export revenues shared with these classes is reduced.

The Board finds that the costs of the URA should not be deducted from export revenue. Uniform rates are to continue according to *The Manitoba Hydro Act*, CCSM c H190. Regardless of the legislative or prior Board intent, uniform rates are paid for by domestic customers. Previous cost of service methods that allocated the URA to exports or the Export class did not alter the fact that the nature of Manitoba Hydro's export business results in these costs being borne by domestic customers. The Board's view is that the URA is a matter of policy and that the costs of the URA are caused by policy, rather than energy, demand, or the number of customers. The URA is a revenue responsibility transfer, primarily from the Residential class to other classes. There is no cost causation basis for deducting the URA from export revenue, nor does the legislation require such an approach. Any impacts of the Board's COSS treatment of uniform rates on RCC ratios are a matter for consideration in rate design, not cost of service.

The Board finds that the assets in the Diesel zone are not causally linked to the realization of export revenues. Therefore, there is no cost causation basis for the crediting of any export revenues to the Diesel class. As previously noted, any resulting need to make adjustments to rates should be raised in a rate-setting process.

7.0 Generation Assets

To provide electricity for Manitobans, Manitoba Hydro operates 15 hydroelectric generating stations on various river systems within Manitoba, as well as two thermal generating stations. Manitoba Hydro also imports electricity from various entities in neighbouring jurisdictions, most notably the U.S., as well as purchasing electricity from independent wind generating stations within Manitoba.

Each generating station converts energy from a source, such as water flowing in a river, wind, or combustion of fossil fuels, into electricity. The electricity from each generating station is transported from the generating station to a transformer and switching substation. The wires leading to the substation and the transformers and switches within the substation are called generation outlet transmission. The substation is the “bridge” to Manitoba Hydro’s networked transmission system and allows the electric output from the generating station to flow to Manitoba Hydro’s customers throughout the province.

In the case of the Manitoba Hydro’s three hydroelectric generating stations on the Lower Nelson River (Long Spruce, Kettle, and Limestone), their output is connected together with wires, transformers, switches, and stations. This grouping of assets is called the Northern Collector System. The Northern Collector System conveys the output of these three generating stations to the start of the high voltage direct current (“HVDC”) transmission system at two HVDC converter stations (Radisson and Henday). From these two (and soon to be a third, Keewatinohk) converter stations, electricity is converted from high voltage alternating current (“AC”) to HVDC and transmitted to southern Manitoba on two HVDC transmission lines called Bipole I and Bipole II. Near Winnipeg, the Bipoles terminate at the Dorsey converter station. A third Bipole, called Bipole III, is being constructed and will terminate at the Riel converter station on the eastern side of Winnipeg. Dorsey (and Riel) converts the HVDC electricity to AC electricity and then connects to the networked transmission system, which in turn carries electricity to consumers in southern Manitoba as well as to export customers, primarily in the United States. Manitoba Hydro selected HVDC lines over conventional

AC transmission lines because they were more economical to construct, more efficient to operate with lower line losses, and the HVDC converters have control systems that provide stability to the networked transmission system.

Dorsey and Riel stations also have AC transformation and switching components that are part of conventional AC substations.

The fact that the Lower Nelson generating stations, and other hydroelectric generating stations, are located far from where electricity is used in Manitoba means that the electricity must be transported long distances. The Lower Nelson generating stations were feasible because the HVDC system facilitated the cost-effective transmission of their electricity output to the southern parts of Manitoba where there is greater demand for electricity.

Manitoba Hydro also imports electricity from neighbouring jurisdictions. Import purchases of electricity may be used at times of low hydroelectric generation, such as during a drought, or they may be used to meet a high demand for electricity in Manitoba that exceeds the capacity of Manitoba Hydro's generating stations.

Generation Functionalization

Manitoba Hydro's Position

Based on Manitoba Hydro's functionalization of costs as Generation, Generation accounts for 65% ($1.1 billion) of the PCOSS14 Amended revenue requirement.

Manitoba Hydro proposes functionalizing all generating stations as Generation, as well as the Northern Collector System, which is considered generation outlet transmission. Generation outlet transmission connects generating stations to the networked transmission system but, in Manitoba Hydro's view, generation outlet transmission is not used or useful if the generator is not operating. Wind energy and import purchases are also functionalized as Generation because they serve the same purpose as Manitoba

Hydro's generating stations, which is to supply energy to the networked transmission system.

In response to recommendations from GAC, Manitoba Hydro has added the following generation outlet transmission facilities to the Generation function:

- Wuskwatim generating station to Wuskwatim switchyard 230kV lines,
- St. Leon wind farm 230kV lines,
- St. Joseph wind farm 230kV lines,
- Pointe du Bois-Rover 66kV lines,
- Slave Falls-Pointe du Bois 115kV lines, and
- Pointe du Bois switching station.

However, Manitoba Hydro rejects GAC's recommendations to include additional transmission facilities in the Generation function, reasoning that these facilities are networked transmission facilities. Since these additional facilities are part of the networked transmission system, they should be functionalized as Transmission. Manitoba Hydro also proposes to functionalize the Bipoles I, II, and III, and the Dorsey and Riel HVDC converter facilities as Generation. These items are addressed in a subsequent section in this Order.

Manitoba Hydro acknowledges that a larger share of its transmission facilities are functionalized as Generation compared to other utilities, but notes that Manitoba Hydro has a uniquely high proportion of remote generating facilities compared to other utilities.

Intervener Positions

GAC identified additional transmission facilities that should be included in the Generation function. These facilities include transmission lines from the Wuskwatim switching station to Thompson, Snow Lake, and The Pas. GAC also identifies transmission lines connecting to the Grand Rapids and Jenpeg generating stations and to most Winnipeg River generating stations that should be functionalized as Generation, as well as generator switching stations.

Board Findings

The Board finds that Manitoba Hydro's hydraulic and thermal generating station costs, including operations and maintenance, fuel, and water rental costs, as well as the costs related to wind energy purchases, import purchases, Midcontinent Independent System Operator ("MISO") fees, transmission fees, National Energy Board fees, and Manitoba Hydro's trading desk are to be functionalized as Generation.

The Board finds that certain transmission facilities should be functionalized as Generation, including the Northern Collector System, the northern converter stations Henday, Radisson, and Keewatinohk, and the additional generation outlet transmission assets as agreed to by Manitoba Hydro, identified above. Generation outlet transmission is functionalized as Generation because this transmission is necessary to connect generating stations to the networked transmission system and power flows in only one direction on these lines. If the generating station is not in service, no power would flow on these lines and they provide no benefit to the networked transmission system. It is also standard in the industry for generation outlet transmission facilities to be functionalized as Generation. Functionalization of the HVDC facilities, including the Bipoles, is addressed in a subsequent section of this Order.

Generation Classification

Manitoba Hydro's Position

Manitoba Hydro's planning criteria for new generation includes both energy and capacity considerations. Manitoba Hydro must plan to meet its customers' winter peak demand as well as annual energy requirements assuming the water conditions will mirror minimum historic (otherwise known as dependable) water flows.

Manitoba Hydro proposes to classify all Generation function costs as Energy-related. It justifies this primarily on the nature of its hydraulic system, arguing that energy constraints tend to drive most of its investments in new generation.

Manitoba Hydro states that the adoption of weighting factors to capture the value of energy at times of higher demand is integral to its method to classify all Generation costs as Energy. The weighting factors are based on what Manitoba Hydro characterizes as its short-run marginal value of generation. Depending on the situation with water flows and transmission constraints, the marginal value of generation is based on the value of energy exports to the MISO region, the incremental cost of generating electricity with its thermal generating stations, or the cost of imports. The marginal value of energy is also reflective of how Manitoba Hydro plans and operates its predominantly hydraulic generation fleet, which is operated in order to take advantage of varying prices at different times.

Marginal values are greater during peak periods, which recognizes the value of generation capacity. During peak periods, demand for electricity in MISO cannot be satisfied with the capacity of less expensive baseload generation, so more expensive generation is called on to meet peak demands, which in turn pushes up the peak period market prices. Thus, the market prices reflect the impact of increased demand. Manitoba Hydro explains that including weighting factors in the Generation allocator imparts an implicit Demand classification to the Generation costs because it captures the value of exporting energy during these more expensive peak periods. Manitoba Hydro's Generation allocation method is explained in greater detail in a subsequent section of this Order.

Manitoba Hydro rejects MIPUG's recommendation to classify explicitly a portion of Generation costs as Demand and then apply marginal cost weightings to the Generation allocator.

Intervener Positions

The Coalition supports Manitoba Hydro's proposal to classify Generation costs as Energy-related to recognize that energy is the central cost driver for hydraulic generation. Similarly, GAC agrees that hydraulic and thermal generation costs are Energy-related because new generation is needed to meet energy needs before it is needed to meet capacity needs. GAC submits that the ability to meet peak demand is only a by-product of Manitoba Hydro building hydraulic generation that meets its dependable energy criterion.

MIPUG claims that Manitoba Hydro's proposed approach under-classifies costs as Demand, noting that Manitoba Hydro has confirmed that it considers both capacity and energy in generation planning. While MIPUG accepts Manitoba Hydro's Generation classification treatment for wind costs, MIPUG recommends that all other generating costs receive some peak capacity-related recognition.

MIPUG recommends an explicit Demand classification in the range of 21-23%, based on using either the system load factor or equivalent peaker methods. System load factor is the average demand divided by peak demand. A higher system load factor classifies more cost as Energy; conversely a lower load factor classifies more cost as Demand. The equivalent peaker method estimates the cost of an equivalent peaking generator, which is typically a single cycle combustion turbine, because it is the least expensive generator that can provide capacity (i.e. respond to peak demand). It then considers the cost of the alternative generator (e.g. hydroelectric, coal, etc.) and assumes the ratio of the alternative generator's cost to the equivalent peaker's cost is the same as the ratio of the energy to demand classification. According to MIPUG, Manitoba Hydro should consider using either the system load factor approach or the equivalent peaker methodology to determine the appropriate level of Demand classification for Generation costs.

Board Findings

The Board finds that Generation costs should be classified as both Energy and Demand, with the proportions determined by the system load factor method. The Generation costs to be classified on the system load factor basis include hydraulic generation, gas- and coal-fueled thermal generation, generation outlet transmission, and import purchases. The only exceptions to this approach are wind generation, water rentals, and variable hydraulic operation and maintenance costs, which should be classified as 100% Energy, as discussed further below.

The principal reason for classifying Generation costs as both Demand and Energy is that Manitoba Hydro plans for and invests in assets to satisfy both a winter peak capacity criterion and a dependable energy criterion. Meeting winter peak capacity is a critical requirement in Manitoba Hydro's operations and it drives certain investments. Peak capacity is not a by-product of meeting the dependable energy criterion. For example, hydroelectric facilities can have additional turbines installed in a given generating station that will increase capacity but not increase dependable energy. The additional capacity from these turbines, used in concert with other thermal and contracted resources, help satisfy the winter peak planning criterion. Classifying hydraulic generation, thermal generation, and import purchases as both Demand and Energy reflects the integrated nature of Manitoba Hydro's system and that these resources contribute both capacity and dependable energy and thus have cost causation traced to peak demand and energy consumption.

The Board finds that an explicit Demand classification is warranted. The Board rejects Manitoba Hydro's argument that the Weighted Energy allocator provides a sufficient and implicit Demand classification. Based on the importance of meeting peak demand in Manitoba Hydro's system, the Board finds that an explicit Demand classification should be employed.

The Board rejects the equivalent peaker methodology as too complex and open to continuing argument over the appropriate costs to be used in its calculation.

The Board directs the use of the system load factor because it is straight-forward and generally accepted in the industry. System load factor has a clear cost causation basis as it reflects the factors considered by resource planners when deciding the types of generation resources to add to the system.

The system load factor is to be based on multi-year historical domestic load data and updated for each COSS. Based on that load research data, in the next COSS and in the Compliance Filing from this Order, Manitoba Hydro should propose the appropriate number of years to consider in the calculation of the system load factor. Using multiple years of data will improve the year-over-year stability of the system load factor.

The system load factor methodology used by Manitoba Hydro prior to 2006 is not to be used. This previous methodology grouped the Generation and Transmission costs together, classified them by system load factor, but then considered the Transmission costs to be 100% Demand.

Wind generation, water rentals, and variable hydraulic operation and maintenance costs should be classified as 100% Energy. If Manitoba Hydro incurs other costs in the future, such as for solar generation that are exclusively Energy-related and have no Demand component, then such costs should likewise be classified as 100% Energy. Wind generation is subject to prevailing wind conditions and thus Manitoba Hydro cannot count on wind generation at any specific point in time. For example, Manitoba Hydro cannot call on wind generation to meet its winter peak demand. Since wind generation does not contribute to the winter peak capacity, it should be classified 100% as Energy. Water rentals are paid to the Province for every kWh of hydraulic generation and thus vary directly with energy produced, hence an Energy classification. Similarly, variable hydraulic operation and maintenance costs are costs that are incurred for each kWh of hydraulic energy produced.

Generation Allocation

Manitoba Hydro's Position

Manitoba Hydro's position is that a Weighted Energy allocator should be used to allocate all Generation costs. The Weighted Energy allocator weights the energy by the relative value of exports during twelve separate time periods. In other words, classes that consume more energy will be allocated a greater share of costs, and if a greater proportion of that energy is consumed during peak periods, then the weighting of the allocator further increases the share of costs allocated to those classes. The twelve periods result from dividing up the hours in a year into four seasons with each season having peak, shoulder, and off-peak periods in each day. Energy consumed during peak periods is given greater weighting than energy consumed in shoulder and off-peak periods. Likewise, energy consumed during the winter and summer seasons is given greater weighting than energy consumed during the spring or fall.

The weightings in each of these twelve periods are based on the prices of Manitoba Hydro's Surplus Energy Program ("SEP"). The SEP is a program by which Manitoba Hydro customers can obtain surplus energy at Manitoba Hydro's value of generation, which is typically equal to U.S. market prices. In some instances, such as when Manitoba Hydro is constrained from selling surplus electricity in the U.S. market, the SEP prices are based on Manitoba Hydro's internal cost of generation.

Manitoba Hydro states that its proposed Weighted Energy allocator methodology reflects cost causation because it captures the time-varying economic value of resources. The Weighted Energy allocator also incorporates both equity and efficiency ratemaking goals, while reflecting how Manitoba Hydro plans and operates its largely hydraulic system facilities.

As noted in the Generation classification section above, Manitoba Hydro asserts that the Weighted Energy allocator reflects short-run marginal energy costs and implicitly includes a Demand component.

Manitoba Hydro's proposed Weighted Energy allocator includes a component to reflect capacity, which it calls a capacity adder. In Manitoba Hydro's view, the capacity adder incorporates additional capacity considerations in the allocation of Generation costs. The capacity adder is intended to recognize that, due to changes in market conditions, the capacity component of energy supply may not be adequately reflected in the differential between on-peak and off-peak energy prices. The capacity adder is added to the peak period energy weightings in all four seasons, thus it increases the weighting of energy consumed during four of the twelve periods. Customer classes that consume more energy during peak periods are allocated more Generation costs, and the capacity adder increases that allocation of additional Generation costs.

The capacity adder is based on the Curtailable Rate Program ("CRP") reference discount. The CRP provides participating customers with a credit on their electricity bills in exchange for agreeing to curtail their load when required by Manitoba Hydro. The CRP provides Manitoba Hydro with curtailable load which is available to maintain operating and contingency reserves, and which serves to minimize the disruption to firm customers in the event of loss of generation or transmission.

The CRP reference discount is an estimate of the fixed carrying cost of a single cycle combustion turbine ("SCCT"), discounted to reflect that the curtailments of CRP customers are not as valuable as having a SCCT available to be dispatched at all times. The CRP reference discount is meant to reflect the value of capacity to Manitoba Hydro. The CRP reference discount is used to calculate the credit given to Manitoba Hydro's customers that are on the CRP. In exchange for giving Manitoba Hydro the right to curtail their load, for example during system contingencies, CRP customers receive a credit on their bills.

Manitoba Hydro proposed using the CRP reference discount to calculate the capacity adder instead of MISO capacity auction prices because it is a relatively stable value from year to year, is not as variable as MISO capacity auction prices, and is not as high as the all-in cost of a SCCT.

Intervener Positions

MIPUG's view is that, because of the winter peak capacity constraint, the portion of Generation costs explicitly classified as Demand should be allocated on the basis of the Winter Coincident Peak. The remaining costs (77-79%) classified as Energy should be allocated by Weighted Energy, but without the extra capacity adder used in PCOSS14 Amended. Wind generation costs, which are classified as Energy, should be allocated by Weighted Energy. MIPUG argues that the Weighted Energy allocator used by Manitoba Hydro is too coarse to capture the true peaks on the system that drive investment costs. The result is that the weightings do not accurately reflect the load shape.

The Coalition, GSS/GSM, and GAC agree with the use of Manitoba Hydro's Weighted Energy allocator, but do not support the inclusion of the capacity adder. The Coalition agrees with Manitoba Hydro that the Weighted Energy allocator incorporates both efficiency and equity in the rate making process.

GAC argues that there does not appear to be any justification for the capacity adder as demand does not drive generation costs and domestic consumption does not affect Manitoba Hydro's ability to sell capacity in the short-term opportunity market. Similarly, GSS/GSM maintains that the proposed capacity adder is not sufficiently justified at this time and requires further review The Coalition recommends rejecting the capacity adder because it is not sufficiently justified and may lead to double counting of capacity (first through the MISO market prices and second through imposing the capacity adder).

Board Findings

The Board finds that the Demand component of Generation costs should be allocated by the top 50 Winter Coincident Peak hours. The Energy component of Generation costs should be allocated on unweighted energy.

The top 50 Winter Coincident Peak hours are the 50 hours during the winter season when Manitoba Hydro's aggregate demand reaches its peaks as a result of the combined demand of all of the domestic customer classes. The Winter Coincident Peak allocator reflects the proportional share that each customer class contributes to these peaks. Allocating by Winter Coincident Peak reflects the shape of the domestic load over the course of a year. With no Export class, there is no need to consider the summer coincident peaks when allocating Demand costs. Load research data used to estimate peak loads should consider domestic load peaks and not total generation peaks. Domestic demand in Manitoba is highest during the winter heating season, making Manitoba Hydro's domestic load winter peaking. This was not disputed in the proceeding. However, the Board recognizes that the nature of electrical systems may change over time. If Manitoba Hydro's customer mix and domestic load shape changes and becomes a system with both winter and summer peaks, then it could be appropriate to revisit the use of Winter Coincident Peak to allocate Demand-related costs.

The Board rejects the Weighted Energy allocator because it has an implicit, if limited, recognition of Demand. Weighted energy is therefore not necessary with the Board's explicit recognition of Demand classification. Furthermore, as recognized by Manitoba Hydro, with an explicit Demand classification, including weightings in the energy allocation could result in double-counting the impact of Demand on Generation costs.

Allocating on Winter Coincident Peak and unweighted energy means the COSS methodology no longer includes marginal cost considerations in the allocation of Generation costs. The Board finds that marginal cost considerations are more appropriately addressed in the rate design stage of ratemaking and not the COSS stage. As articulated in the Principles section of this Order, cost causation underpins the COSS methodology, without including other ratemaking goals. Equity and efficiency are ratemaking goals that should be addressed in a rate-setting process such as a GRA. An embedded COSS more accurately reflects cost causation than a marginal cost COSS. Accordingly, the Board approves a Manitoba Hydro COSS methodology based on embedded costs, not marginal costs.

High Voltage Direct Current ("HVDC") System Functionalization

Manitoba Hydro's Position

Manitoba Hydro functionalizes the alternating current ("AC") portions of Dorsey and Riel as Transmission. The Northern Collector System is an AC transmission system that is considered generation outlet transmission and is functionalized as Generation, as discussed previously in this Order.

Bipoles I, II and III

Manitoba Hydro asserts that its high voltage direct current ("HVDC") transmission system is designed to carry northern Manitoba generation output, providing both capacity and energy to the main transmission network. Bipoles I and II are therefore an extension of and should be functionalized as Generation as they connect remote northern generation to southern load centres.

Manitoba Hydro submits that Bipole III should also be functionalized as Generation as it will function identically to Bipoles I and II, is not required in the absence of northern generation, does not function as grid transmission as the power flows in only one direction, and is required for generation reliability across many hours of the year. The loss of a Bipole would mean the loss of a generator.

Manitoba Hydro rejects MIPUG's assertions that Bipole III should be functionalized as Transmission because Bipole III is not required in the absence of northern generation. The generation reliability enhancement provided by Bipole III is required in both the winter and summer seasons.

Dorsey and Riel Converter Stations

In PCOSS14 Amended, Manitoba Hydro changed the functionalization of the HVDC portion of Dorsey from Transmission to Generation. Even though Manitoba Hydro previously functionalized the HVDC portion of Dorsey costs as Transmission, Manitoba Hydro states that it is not bound by past practice in its COSS methodology. Manitoba Hydro submits that the primary role of the HVDC facilities situated at Dorsey (and Riel) is to make northern generation available to the southern grid. In the absence of the conversion of direct current ("DC") power to AC power at Dorsey, the power is not useable by Manitoba Hydro's customers.

Manitoba Hydro proposes to functionalize the Riel converter station the same as Dorsey: the HVDC portion functionalized as Generation and the AC portion as

Transmission. Riel is intended to act in the same manner as Dorsey and will fulfill the same role.

Intervener Positions

Bipoles I, II, and III

The Coalition supports Manitoba Hydro’s proposed functionalization of Bipoles I, II and III as Generation.

While MIPUG agrees that Bipoles I and II should be functionalized as Generation, MIPUG maintains that Bipole III does not meet the threshold for functionalization as generation outlet transmission, and therefore should be functionalized as Transmission. MIPUG has concerns with the extent of Manitoba Hydro’s use of the generation outlet transmission category, stating that Manitoba Hydro excessively functionalizes transmission assets as Generation.

MIPUG argues that Bipole III is a reliability project, as opposed to an asset for connecting generation, because Bipole III was proposed and justified before the Clean Environment Commission (“CEC”) as a necessary project without any consideration or linkage to new generation. The CEC justification was premised on Manitoba Hydro’s load growth over the past 30 years resulting in an unacceptable gap between generation available without Bipoles I and II and the Manitoba load. Bipole III was not part of the Keeyask business case and was not considered during the NFAT for Manitoba Hydro’s Preferred Development Plan which included Keeyask and Conawapa.

Dorsey and Riel Converter Stations

The Coalition and GAC support Manitoba Hydro’s functionalization of the HVDC-portion of Dorsey and Riel as Generation as being consistent with Manitoba Hydro’s approach to functionalizing Transmission facilities that bring generation to the grid network as Generation.

MIPUG takes the position that the HVDC-portion of Dorsey does not meet the threshold necessary to be functionalized as generation outlet transmission, and should therefore continue to be functionalized as Transmission. Dorsey provides system stability benefits to the transmission system, without which Manitoba Hydro would incur significant additional transmission costs. MIPUG also advances that, since Riel is entirely aligned with the Bipole III project (which MIPUG asserts should be functionalized as Transmission) and because Riel is not cited to provide other system wide benefits, it should be functionalized as Transmission.

MIPUG also identifies that Dorsey has been, and continues to be, included in Manitoba Hydro's Transmission Tariff as a Transmission asset.

Board Findings

<u>Bipoles I, II, and III</u>

The Board finds that Bipoles I and II should be functionalized as Generation. This functionalization was not contentious in this proceeding. Bipoles I and II connect northern generation with southern load centres, acting as extensions of the northern generators, not as networked transmission. Power flows in only one direction on the Bipoles and the loss of a Bipole would result in the loss of electricity generated in northern Manitoba.

The Board also finds that Bipole III should be functionalized as Generation. Bipole III will function in the same manner as Bipoles I and II. Because Bipole III provides redundancy for Bipoles I and II, which are functionalized as Generation, Bipole III provides generation reliability to Bipoles I and II, not reliability for the networked AC transmission system. Notwithstanding that Bipole III was excluded from the NFAT business case for Keeyask and Conawapa, Keeyask requires Bipole III in order to transmit Keeyask's full output.

Bipoles I, II and III should be classified using the system load factor method and allocated as the Board has directed for other functionalized Generation costs.

Dorsey and Riel Converter Stations

The Board finds that HVDC portions of the Dorsey and Riel converter stations should be functionalized as Generation. The Board sees the purpose of Dorsey and Riel to be a part of the Bipoles as extensions of northern generation. Without northern generation, the HVDC portions of Dorsey and Riel have no function. The HVDC converters are integral for the conversion of DC power into AC for use on the networked grid. Without HVDC converters, the Bipoles have no function. A Generation functionalization is therefore more appropriate than a Transmission functionalization.

The Board also finds that the costs of Dorsey and Riel should be classified as both Energy and Demand, consistent with the Board's consideration of not only the primary use or benefit of an asset, but the secondary uses and benefits as well. The classification of the costs of Dorsey and Riel as both Energy and Demand addresses the multiple benefits of these assets. As the Board directed with Generation-functionalized costs, the costs classified as Demand should be allocated on Winter Coincident Peak and the costs classified as Energy should be allocated on unweighted energy.

8.0 Transmission Assets

Transmission assets are those components of the electricity system that transmit the power generated at generating stations to some large end users but mostly to the local distribution system located throughout Manitoba. Transmission assets connect with the substation that is part of the generation outlet transmission and terminate at a substation that is part of either the lower voltage Subtransmission or Distribution system.

Transmission assets include substations and the switching gear and transformers within them, and transmission lines which include towers and conductors (or wires). The Transmission system consists of both networked transmission and radial transmission. Networked transmission means that the transmission lines are interconnected with each other to provide multiple redundant paths for electricity to flow. This is important in case there is a fault or interruption on one transmission line: the redundancy allows all consumers to continue to receive electric service. Radial transmission means there is only a single path for electricity to flow without any redundancy.

Assets functionalized as Transmission are traditionally classified as either Demand or Energy generally with more weighting to Demand than to Energy. Demand refers to the instantaneous load, while Energy refers to load over a period of time, also known as consumption.

Transmission Functionalization

Manitoba Hydro's Position

Based on Manitoba Hydro's functionalization, Transmission costs accounts for 9% ($153 million) of the PCOSS14 Amended revenue requirement. Manitoba Hydro defines its Transmission function to include its transmission assets that operate at voltages in excess of 100kV (">100kV").

Manitoba Hydro functionalizes some transmission assets as Generation, as described previously in this Order. These include generation outlet transmission such as the Northern Collector System, the Bipoles, and the high voltage direct current ("HVDC") converter stations including Dorsey and Riel.

The remaining transmission assets that Manitoba Hydro functionalizes as Transmission include the domestic networked grid of alternating current ("AC") transmission lines and substations operating in excess of 100kV, the interprovincial interconnections to Saskatchewan and Ontario, and the U.S. interconnections.

Manitoba Hydro sub-functionalizes Transmission into Tariffable Transmission and Non-Tariffable Transmission. Tariffable Transmission may be used by third parties that transmit power through Manitoba. The distinction between Tariffable and Non-Tariffable recognizes that third parties should only be charged for Transmission assets that they would or could use when transmitting power through Manitoba. Non-Tariffable Transmission includes radial lines that serve only domestic customers; third parties do not make use of these lines and segregating these costs from Manitoba Hydro's Transmission Tariff means they do not pay for these costs.

Intervener Positions

All parties agreed with the functionalization of the domestic AC grid operating at voltages greater than 100kV, the interprovincial interconnections, and the U.S. interconnections as Transmission.

Board Findings

The Board finds that the domestic AC transmission assets operating at voltages greater than 100kV, interprovincial interconnections, and U.S. interconnections should be functionalized as Transmission. The costs of domestic AC transmission are incurred to: meet higher peak demand, maintain or enhance transmission network reliability, or geographically expand the AC network to serve additional load. For the U.S. interconnections, the Board concludes that these assets are functionally Transmission because the lines are bidirectional and the lines are sized for load as opposed to generation output.

Classification and Allocation of Transmission Costs

Manitoba Hydro's position

Manitoba Hydro classifies 100% of its AC transmission system, except for its U.S. interconnection costs, as Demand-related.

AC Transmission System

As noted by Manitoba Hydro, once generation-related transmission costs are identified, there is little controversy among the parties with regards to the treatment of >100kV transmission assets, with the exception of the US Interconnections. Other than the U.S. Interconnections, Manitoba Hydro proposes classifying all grid Transmission including interprovincial interconnections as Demand and allocating these costs using a 2 Coincident Peak ("2CP") allocator. The 2CP allocator is calculated by averaging the peak demand in each of the top 50 summer peak hours and top 50 winter peak hours.

Manitoba Hydro maintains that Transmission costs should be allocated using a 2CP allocator to recognize the domestic winter peak as well as the export-related summer peak. Beginning with PCOSS14 Amended, the peaks are defined as generation peak plus imports and domestic wind purchases. Thus, the peaks include total domestic load and exports. Previously, wind purchases and imports were excluded from the determination of the peaks used to calculate the 2CP allocator.

Radial taps are high voltage transmission lines that directly connect to customers in the GSL >100kV class. Manitoba Hydro recognizes that there is justification to directly assign the cost of these taps to the GSL >100kV class, since these lines are not used by any other classes. However, the total cost of the radial taps of less than $250,000 is considered small by Manitoba Hydro such that the changing of the allocation does not make a material change to the COSS results. In Manitoba Hydro's view, adding to the complexity in the COSS model is not warranted given the immateriality of the cost. Manitoba Hydro proposes to allocate the radial taps along with other Non-Tariffable Transmission to all domestic customer classes.

U.S. Interconnections

Manitoba Hydro proposes classifying the U.S. Interconnection costs as Energy, and allocating the costs using Weighted Energy. Manitoba Hydro argues that the primary role of the U.S. Interconnections is the transfer of energy over longer time periods for export and import transactions, supporting an Energy classification for the costs. Its rationale for using Weighted Energy in allocating the costs is that the U.S. interconnections:

- provide a source of generation reliability,
- provide an outlet for Manitoba generation surplus to domestic need,
- facilitate economic exchanges during all time periods,
- allow for sharing of capacity resources due to load diversity, and
- allow for sharing of generation contingency reserves with other utilities.

Manitoba Hydro submits that the use of the Weighted Energy allocator recognizes the importance of peak periods, rather than using a 2CP allocator that only considers peak hours. Manitoba Hydro maintains that an allocation based on Weighted Energy accurately captures the time pattern of foregone value of the consumption of electricity (i.e. outage cost) as a consequence of supply-side events

Intervener Positions

The Coalition supports the continued use of a 2CP allocator for Tariffable Transmission costs. The Coalition further asserts that Non-Tariffable Transmission costs should be allocated using a Domestic load-based 2CP allocation factor, as opposed to a 2CP allocator based on Domestic and Dependable Exports.

The Coalition agrees with Manitoba Hydro's approach to the U.S. interconnections and argues that this approach recognizes that the interconnections are critical to baseload generation (as opposed to peak load). GAC also supports Manitoba Hydro's classification and allocation of the U.S. interconnections as a reasonable approach for lines primarily driven by the opportunity for export sales in most years and imports in drought conditions.

MIPUG rejects Manitoba Hydro's proposal to classify U.S. interconnections as Energy. MIPUG asserts that there is no compelling argument to treat these lines differently than AC transmission, especially since, for example, Manitoba Hydro classifies interprovincial interties as Demand, not Energy. MIPUG also argues that the U.S. Interconnections provide a reliability benefit related to avoided outages at peak times and that Manitoba Hydro's approach is inconsistent with how costs are recovered on these lines under Manitoba Hydro's Transmission Tariff. MIPUG also asserts that classifying Transmission as Energy is highly unusual and is not common in other jurisdictions.

Board Findings

The Board finds that domestic AC transmission and interprovincial interconnections should be classified as 100% Demand and allocated on a Winter Coincident Peak basis. The Board finds that U.S. interconnections should be classified on the basis of system load factor, with the Demand portion allocated on the basis of Winter Coincident Peak and the Energy portion on the basis of unweighted energy. The Board finds that the cost of radial taps should be directly assigned to GSL >100kV customers.

For domestic AC and interprovincial transmission lines, the Board finds that these costs should be classified as 100% Demand and allocated on the basis of Winter Coincident Peak, based on the domestic load in the top 50 winter hours. The possible exception to this approach to interprovincial lines is the proposed Saskatchewan interconnection, but the Board does not have enough information on this interconnection to make a determination at this time. The Board notes that, of the utilities whose Transmission classification is on the record of this proceeding, there is no consistent classification of Transmission costs. However, classification of fixed costs as 100% Demand appears to be more prevalent. A 100% Demand classification is appropriate because the sizing and resulting cost of AC transmission lines is directly related to their ability to meet demand. Furthermore a sufficient number of AC transmission lines must be constructed to meet peak loads with adequate redundancy. Interprovincial interconnections are to be classified and allocated along with the AC transmission costs because the interprovincial lines also serve loads along their route. Unlike the U.S. interconnections, interprovincial interconnections do not have firm import capability into Manitoba and so these lines do not provide any generation-related benefits which would warrant an Energy classification.

The Board finds that on a cost causation basis, the cost of radial taps should be directly assigned to GSL >100kV customers as these lines are solely used by GSL >100kV customers.

The Board finds that the U.S. interconnections should be classified on the basis of system load factor. The Demand portion should be allocated on the basis of Winter Coincident Peak, based on the domestic load in the top 50 winter hours. The Energy portion should be allocated on the basis of unweighted energy. The Board identifies a number of benefits of the U.S. interconnections related to both Demand and Energy. The U.S. interconnections assist Manitoba Hydro in meeting peak load through exchanges of Manitoba Hydro's excess summer capacity for U.S. utilities' excess winter capacity. The U.S. interconnections provide access to contingency reserves through the MISO - Manitoba Hydro Contingency Reserve Sharing Group agreement. The U.S. interconnections allow Manitoba Hydro to export energy to the U.S. market, under both firm bilateral contracts and as opportunity sales into the market. The U.S. interconnections also provide access to energy resources for import when economic, or in drought conditions.

In totality, the Board finds that these benefits are the same as those provided by generating stations. The U.S. interconnections provide reliability that is more analogous to generation reliability than to transmission reliability. Transmission planning may not rely on interconnections to the same extent as domestic transmission because the power flow involves a neighbouring area not under direct control of Manitoba Hydro. The Board therefore finds that an approach that splits the interconnection classification between Demand and Energy, with an emphasis on Energy, is justified and appropriate. This is the same classification approach that the Board directs for Generation. System load factor should be used to define the Demand and Energy classification split for the U.S. interconnection costs. The same as for most Generation resources, the Demand portion of the U.S. interconnection costs should be allocated by Winter Coincident Peak. A Summer Coincident Peak is not the appropriate allocator as there is no load-serving obligation to serve the peak amount of export that goes across the U.S. Interconnection. The Energy portion of the U.S. interconnection costs should be allocated by unweighted energy.

9.0 Subtransmission Assets

Subtransmission is a subset of Transmission. Many of the same assets included in the Transmission function are also in the Subtransmission function, such as substations, switching stations, transformers, towers, and wires. The distinction between Transmission and Subtransmission is based on the voltage at which these assets operate.

The Subtransmission function currently includes the costs for lower voltage transmission lines (below 100kV but typically 66kV and 33kV) and the low voltage side of substations (unless the low voltage side is less than 33kV).

Subtransmission Functionalization

Manitoba Hydro's Position

Based on Manitoba Hydro's functionalization of costs as Subtransmission, Subtransmission accounts for 4% ($64 million) of the PCOSS14 Amended revenue requirement.

The GSL >100kV class is served by higher voltage transmission lines. Consequently, in PCOSS14 Amended, the GSL >100kV class is not allocated any Subtransmission costs. Manitoba Hydro submits this is justified because it is contrary to established cost of service principles to allocate costs to a class for assets that they do not use.

Manitoba Hydro states that, for reliability reasons, Subtransmission is not a substitute for Transmission. The Transmission system is a networked system with redundant paths for power to flow. Unlike Transmission, Subtransmission is used for local transmission and is not usually networked.

Intervener Positions

MIPUG supports Manitoba Hydro's proposed approach and agrees that Subtransmission costs should only be allocated to those customers who use these facilities.

According to MIPUG, assigning responsibility for Subtransmission costs to GSL >100kV customers would violate a long-standing cost of service principle to only allocate costs to classes for assets that relate to the power service being delivered to their class. MIPUG's evidence was that GSL >100kV customers pay directly for their own substations and, therefore, should not be assigned responsibility for costs of Subtransmission substations. GSL >100kV customers do not experience savings by Manitoba Hydro having a Subtransmission system.

GAC contends that Subtransmission is really an extension of the Transmission system, but at a lower cost. If not for 33kV and 66kV lines, GAC argues, additional transmission lines at voltage greater than 100kV would be required at a greater cost. By not allocating Subtransmission costs to GSL >100kV class customers, GAC concludes that this class gets an unfair benefit. More specifically, GAC says it is not fair to penalize customer classes that can be served at a lower voltage (and less expensively) by excluding the GSL >100kV from Subtransmission cost allocations. In the alternative, if Subtransmission is treated as a separate function, GAC recommends excluding some Distribution load that is served from the >100kV Transmission system from any Subtransmission cost allocations. Consistent with the principle of not charging customer classes for assets they do not use, GAC's basis for this exclusion is that 35% of the Distribution load is served directly from the Transmission system and does not make use of the Subtransmission system.

With respect to excluding a portion of the Distribution load from the allocation of Subtransmission costs, MIPUG states that this ignores the concept of a "class" defining the rates to be paid - the COSS does not attempt to identify the costs to serve an individual customer. In MIPUG's view, excluding some Distribution load from allocation of Subtransmission costs would be akin to excluding some customers situated in northern Manitoba from allocations of Bipole costs.

The Coalition's expert evidence supports Manitoba Hydro's use and definition of a Subtransmission function as being consistent with industry norms, as is the classification of Subtransmission as Demand-related. However, the Coalition is of the view that additional study is needed to resolve whether Subtransmission is an extension of Transmission and not a separate function, and that this matter cannot be decided on the record of this proceeding.

Board Findings

The Board finds that the Subtransmission function is to remain a separate function from Transmission, encompassing transmission assets operating at voltages less than 100kV but greater than or equal to 33kV. The Board rejects GAC's proposal to include Subtransmission costs within the Transmission function and GAC's alternate proposal to exclude some of the load of distribution-connected customers from the allocation of Subtransmission costs.

GSL >100kV customers do not take service at voltages such as 66kV or 33kV, and thus they should not be allocated the costs of substations and lines at these voltages. GSL >100kV customers pay for their own transformers and substations. It would be inappropriate to charge them for these same costs as part of the Subtransmission function. The GSL >100kV loads incur lower line losses and transformation costs, and should have lower costs allocated to them.

The Board further rejects GAC's alternate proposal that, if the Subtransmission function remains, Subtransmission costs be allocated only to the Subtransmission load. Such a proposal would treat the loads differently within a class. Some distribution loads are not served by Subtransmission, but Manitoba Hydro still incurs voltage transformation costs for these loads.

The Board concludes that there is no need to make assumptions on the split between Subtransmission and Transmission costs. The Board notes that Manitoba Hydro tracks the cost of Subtransmission assets separately from Transmission assets. The separate functionalization of Transmission and Subtransmission is a long-standing aspect of Manitoba Hydro's COSS.

Classification and Allocation of Subtransmission Costs

Manitoba Hydro's Position

Manitoba Hydro states that Subtransmission lines (33kV and 66kV) and substations must be sized in order to meet the Non-Coincident Peak ("NCP") demand from each class which is the maximum demand of each customer class regardless of when it occurs. Therefore, these costs are driven by Non-Coincident Peak as opposed to the overall system Coincident Peak. As a result, in PCOSS14 Amended, Subtransmission is classified as Demand and is allocated on the basis of Non-Coincident Peak to the domestic customer classes.

Intervener Positions

If Subtransmission is functionalized separately from Transmission, GAC proposes to allocate Subtransmission costs based on an estimate of class contribution to the peak loads on the Subtransmission stations and lines. GAC submits that this is appropriate because each Subtransmission line serves a variety of classes, and thus the capacity of the line is determined by the combined peak load of the classes. Absent sufficient data to calculate class contributions to peak loads on Subtransmission facilities, GAC recommends that Subtransmission be allocated with all other load-serving Transmission using the 2CP allocator, adjusted to remove export loads.

The Coalition states that, while the classification of Subtransmission as Demand-related is appropriate, there is no clear evidence that a Non-Coincident Peak allocator is more appropriate than a Coincident Peak allocator.

MIPUG supports Manitoba Hydro’s classification of Subtransmission as Demand and the use of Non-Coincident Peak to allocate Subtransmission costs as reflecting industry standard methods.

Board Findings

The Boards finds that Subtransmission should be classified as 100% Demand and allocated by Winter Coincident Peak. This reflects cost causation, as Subtransmission planning and operations are similar to Transmission, which is also classified and allocated on this basis. In addition, there is sufficient evidence to suggest that Manitoba Hydro’s Subtransmission system serves a variety of customer classes instead of distinct classes in different areas, the latter of which would indicate Non-Coincident Peak would be a more appropriate allocator. Manitoba Hydro does not have sufficient data to either calculate or to justify a substation-by-substation Coincident Peak allocator.

10.0 Distribution Assets

Poles and wires are the most visible elements of the Distribution system, running mainly on public thoroughfares and residential streets. Wires may also be underground. The Distribution system includes substations, which receive higher voltage electricity from the Transmission or Subtransmission systems and transform the voltage to lower voltages. The Distribution system also includes distribution transformers which convert electricity at primary voltage (greater than 750V) to secondary voltage (750V and below). Distribution transformers are sometimes referred to as pole transformers due to the placement on utility poles. Distribution transformers are also the visible, above ground part of the otherwise underground distribution system that serves newer subdivisions. Primary distribution lines are the wires that transfer power from the distribution substation to the distribution transformer or directly to some larger customers, while secondary distribution lines connect the distribution transformer to the end users.

Service drops, also known as services, are wires that connect individual homes and businesses to either the primary or secondary voltage systems, and can be either above ground to a mast on the building or underground to the meter. For multi-unit buildings, such as apartments, there is usually a single service drop serving the building, such that many customers are served from one service drop. Service drops connect to meters located adjacent to or within homes and businesses.

Distribution Functionalization

Manitoba Hydro's Position

Manitoba Hydro functionalizes as Distribution those assets that operate below a voltage of 33kV, including poles, wires, the low voltage side of substations, meters, and distribution transformers. Based on Manitoba Hydro's functionalization, distribution accounts for 17% ($284 million) of the PCOSS14 Amended revenue requirement.

Intervener Positions

The functionalization of Distribution assets was not contentious in this proceeding and the interveners did not put forward positions.

Board Findings

The Board finds that Manitoba Hydro's proposed functionalization of Distribution assets as those assets that operate below a voltage of 33kV, including poles, wires, the low voltage side of substations, meters, and distribution transformers is appropriate.

Classification of Poles and Wires

Manitoba Hydro's Position

Since 1991, Manitoba Hydro has classified poles and wires as 60% Demand and 40% Customer. In Manitoba Hydro's view, a Customer classification is justified because the design for poles and wires considers line length and population density which are, in turn, driven by where customers choose to locate. Manitoba Hydro supports the use of Customer classification for poles and wires in order to reflect the length of wires and number of poles needed to reach different customers. The classification of poles and wires as both Demand and Customer is consistent with industry practice and with the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual.

Intervener Positions

GAC's view is that poles and wires should be classified as 100% Demand, since customer numbers do not influence the cost. Even in cases where poles and wires are being extended to serve remote or rural customers, the decision to proceed with the extension is based on the economics and revenues of the extension, which in turn are based on the demand that is expected. GAC states that classification as 100% Demand is common in the industry.

The Consumer Coalition (“Coalition”) and GSS/GSM support classifying a portion of the distribution poles and wires costs as Customer-related, but recommend that Manitoba Hydro update the Demand-Customer split due to the age of the underlying analysis.

Board Findings

The Board finds that distribution poles and wires should be classified as 100% Demand. This reflects cost causation as the sizing of poles and wires is based on demand. Manitoba Hydro’s approach of a 60% Demand and 40% Customer classification split is based on an arbitrary assumption that the number of customers influences the cost of poles and wires. The Board does not find sufficient evidence in the proceeding to support this assumption. Although geography influences the cost of poles and wires, the correlation between geography and customer numbers is not established. A geographically remote customer will cause Manitoba Hydro to incur poles and wires costs to extend service; however additional customers along this route can be added at no additional cost, with respect to poles and wires. Likewise, large numbers of customers in densely populated areas do not cause additional poles and wires costs on the basis of their numbers. Their geography determines part of the costs (along with the total demand) but in most cases the poles and wires costs are completely independent of the number of customers. In addition, industry practice in this area is inconsistent.

Classification of Other Distribution Costs

Manitoba Hydro’s Position

Manitoba Hydro proposes that distribution substations and distribution transformers be classified as 100% Demand, while service drops, meter investment, and meter maintenance should be classified as 100% Customer-related.

Intervener Positions

The classification of other Distribution costs was not contentious in the proceeding. The Coalition takes no issue with Manitoba Hydro’s proposed classification of substations as

100% Demand as it is consistent with industry practice. Based on its position on allocation of distribution substations and transformers, GAC supports a 100% Demand classification for the costs of these assets.

Board Findings

The Board finds that the costs of distribution substations and distribution transformers are demand-related and therefore should be classified as 100% Demand. Service drops, meter investment, and meter maintenance should be classified as 100% Customer-related.

Allocation of Distribution Demand Costs

Manitoba Hydro's Position

Manitoba Hydro proposes to use Non-Coincident Peak to allocate the Demand-portion of Distribution costs. This is consistent with industry practice and was supported by Manitoba Hydro's consultant, Christensen Associates. Manitoba Hydro accepts that there may be some merit in exploring the allocation of Substation costs by analyzing each class's contribution to Substation peak loads, but estimates that the resulting allocations may not be substantially different than using Non-Coincident Peak. However, Manitoba Hydro states that it does not have data sets and inputs to support GAC's allocation method, and that it could only acquire the necessary data at significant cost.

Intervener Positions

GAC recommends that the Demand allocator for distribution substations as well as for poles and wires be based on estimates of each class's contribution to the peak loads of those facilities. GAC maintains that Non-Coincident Peak is not appropriate to allocate substation or poles and wires costs because each of these facilities serves more than one class, so it is the contribution of several classes to the coincident peak demand that determines the sizing and resulting cost of these facilities. Given the limitations in

Manitoba Hydro's data with respect to substation and feeder loading, GAC's view is that the best available measure of Distribution loads is the 2CP allocator, but the summer coincident peaks should be weighted at 50% of the winter peaks.

The Coalition submits that there is no clear evidence on whether a Coincident Peak or Non-Coincident Peak allocator is more appropriate for Distribution Demand costs. The Coalition recommends that Manitoba Hydro undertake an analysis of substation and distribution-line peak loading to determine which allocator is more appropriate. In the meantime, it is reasonable for Manitoba Hydro to continue to use Non-Coincident Peak.

The allocation of distribution transformers using Non-Coincident Peak was not contentious.

Board Findings

The Board finds that the Demand component of Distribution costs should be allocated based on each class's Non-Coincident Peak demand. Non-Coincident Peak is the industry standard for allocation of Distribution costs. As there is less load diversity in the Distribution function, Distribution assets may primarily serve only one class. This increases the probability that a certain class causes the peak load, which supports the Non-Coincident Peak allocator.

The Board finds that Manitoba Hydro does not have sufficient data for substations across the province to support estimating the coincident demand imposed by each class. Non-Coincident Peak is the most reasonable approach absent further data. If Manitoba Hydro develops additional data in the future, it should revisit whether Non-Coincident Peak is still the most appropriate allocator.

Primary and Secondary Voltage Service

Manitoba Hydro's Position

Manitoba Hydro does not sub-functionalize poles and wires into primary voltage and secondary voltage (except for underground distribution). As such, it is necessary to make an adjustment so that the GSL 0-30kV class is not allocated costs for the secondary voltage system which it does not use. Since 1991, Manitoba Hydro has used a 30% factor to reduce the distribution poles and wires allocations to the GSL 0-30kV class. Manitoba Hydro accepts GAC's estimate that secondary voltage facilities represent 20% of the distribution poles and wires costs, although Manitoba Hydro cautions that it has no reason to believe its 30% factor is no longer appropriate.

Manitoba Hydro now proposes to separate primary and secondary voltage facilities into separate sub-functions, instead of its current methodology, which is to adjust the allocators.

Intervener Position

GAC identifies four specific subcomponents of distribution poles and wires and estimates the secondary portion of each subcomponent. The estimates are based on professional judgment and, for underground cable, Manitoba Hydro data. GAC's calculation of a weighted average of these estimates results in an estimate that secondary voltage facilities represent 20% of the distribution poles and wires costs. Thus, GAC recommends reducing the allocation to the GSL 0-30kV class by 20%, not the 30% factor that Manitoba Hydro had been using since 1991.

The Coalition's view is that Manitoba Hydro should explicitly separate the costs of primary and secondary voltage facilities into two sub-functions in the COSS. The revenue requirement for distribution poles and wires is $140 million in PCOSS14, which the Coalition states is a material amount. The Coalition recommends that Manitoba Hydro investigate ways to update the percentage split.

Board Findings

The Board finds that Manitoba Hydro should continue with existing methodology whereby the Demand factor for the GSL 0-30kV class used to allocate distribution poles and wires costs is reduced by 30% to account for the fact that this class receives its service at primary voltage. The GSL 0-30kV class does not utilize the secondary voltage system. While an alternative approach was proposed, in the Board's view, more study underpinned by additional data is required before a methodology change would be considered. The Board also notes that there does not appear to be an industry standard to provide guidance.

Based upon the information available, the Board directs Manitoba Hydro to continue with the existing methodology unless and until additional study and data are presented to the Board to justify any methodology changes.

Service Drops

Manitoba Hydro's Position

Manitoba Hydro uses the number of customers connected by the service drops to allocate the costs. GSS, GSM, and GSL 0-30kV customers use three-phase services. Three-phase services are more complex and costly than single phase services. Therefore, Manitoba Hydro uses a five-times weighting. These weighting factors have been used since at least 1991. Manitoba Hydro states that the weighting factors may or may not already take into account the shared service drops but it does not have any supporting data from the time the weighting factors were developed. Manitoba Hydro rejects any changes to its methodology at this time as they have been shown to have virtually no impact on the COSS results.

Intervener Positions

Both GAC and the Coalition object to the allocation of service drop costs based on the numbers of customers and not the numbers of service drops. The Coalition recommends adjusting the customer counts used for allocation of service drops. The Coalition identifies that approximately 103,000 Residential customers are in apartments that are served as GSS or GSM customers. The Coalition's expert witness proposed a methodology that entails prorating the 103,000 Residential customers over the three classes based on the numbers of customers in each class. For example, in PCOSS14, the number of Residential customers is 462,217, which is 87.34% of the total number of

Residential, General Service Small (GSS), and General Service Medium (GSM) customers. Thus, the Residential customer count used in the allocation of service drops is reduced by 87.34% of the 103,000 customers, or 89,959 customers. Reductions are calculated for the GSS and GSM classes using the same methodology.

Similarly, GAC recommends that Manitoba Hydro reflect these shared service drops in its next PCOSS filing. GAC also identifies that some of the weighting factors do not appear to be based on actual cost data. GAC also states that Manitoba Hydro rejects proposed changes to its methodology when they have too large an effect on the RCCs of the some classes, while rejecting proposed improvements that would have only a small effect on the COSS results, such as improving the Service Drop allocator.

Board Findings

The Board finds that an allocator that reflects the number of services drops, not the number of customers, better reflects cost causation. This will avoid potentially over-allocating costs to classes with multiple customers served by single service drops. The Board directs Manitoba Hydro to update its Service Drops cost allocator.

In the interim, until Manitoba Hydro updates its Service Drops allocator, the methodology used should prorate the 103,000 Residential customers over the three classes based on the number of customers in each class. This is more substantiated than Manitoba Hydro's method and it is calculated using current customer numbers.

As part of its comprehensive update of the Service Drops allocator, Manitoba Hydro shall revisit the weightings for GSS, GSM, and GSL 0-30kV 3-phase services. The updated analysis should show evidence that the weightings more accurately weight the cost differences between services drops for different customer classes. Due to the Board's decision to classify these costs as 100% Demand, there are no longer any Customer-related poles and wires costs. Therefore a similar adjustment to the allocation of Customer-related costs for distribution poles and wires is no longer required.

Allocation of Other Distribution Customer Costs

Manitoba Hydro's Position

Manitoba Hydro notes that the weighting factors for meter investment and meter maintenance were developed in 1991. Manitoba Hydro agrees that it is appropriate to update these weighting factors, but proposes to do so when resources are available. Manitoba Hydro does not expect any changes in the weighting factors to have a material impact on the COSS.

Intervener Positions

The Coalition recommends that Manitoba Hydro update the weighting factors for meter investment and meter maintenance as they have not been reviewed in 25 years.

GAC recommends that Manitoba Hydro align these customer allocators with the cost drivers. GAC proposes that Manitoba Hydro progress toward developing data-supported weighting factors for the customer allocators.

Board Findings

The Board finds that the current weighting factors are out-of-date and directs Manitoba Hydro to update its Customer-related allocators and weighting factors for its Distribution costs that are Customer classified. Most of the customer weighting factors have not been updated since at least 1991. These include the weightings for meter investment and meter maintenance, as well as for service drops, as previously mentioned in this Order. As part of this update, Manitoba Hydro should develop a system or methodology to update these weighting factors periodically in order keep the factors up to date.

11.0 Customer Services Function

Manitoba Hydro's Customer Services function costs relate to serving and communicating with customers after delivery of energy. These costs include meter reading, billing, collections, information and customer assistance, advertising, sales, inspections, research and development, rates and cost of service, load research, as well as other departmental costs such as Power Smart Energy Services.

Customer Services Functionalization and Classification

Manitoba Hydro's Position

Based on Manitoba Hydro's functionalization, Customer Services account for 6% ($110 million) of the PCOSS14 Amended revenue requirement.

Manitoba Hydro proposes classifying Customer Services costs as Customer. These costs vary with the number of customers.

Intervener Positions

This issue was not contentious in this proceeding and the interveners did not put forward a position.

Board Findings

The Board finds that these services vary with the number of customers and should be classified as Customer Services.

Allocation of Customer Services General Costs

Manitoba Hydro's Position

Manitoba Hydro has several allocators for Customer Services costs. One of these allocators, which Manitoba Hydro calls C10, allocates costs related to customer service departments such as Consumer Consultation and Information, Municipal and

Community Relations, Service Extensions, Load Research, and other departments. Manitoba Hydro's C10 allocator is based on estimates of the time and efforts various departments devote to each customer class, which are then weighted by the budget for each area. The costs within Consumer Consultation and Information include costs related to Key Accounts and Major Accounts, which apply to larger customers such as GSL customers, as well as a generic Customer Service category.

Manitoba Hydro has agreed to review the C10 allocator but is of the view that GSL customers should not be excluded from the Customer Service costs category in advance of this review.

Intervener Positions

MIPUG's expert witness identifies $1.2 million of Customer Service costs in PCOSS14 that, in his view, are incorrectly attributed to the GSL 30-100kV and GSL >100kV classes. MIPUG does not agree that the costs within the generic Customer Service sub-category of Consumer Consultation and Information, such as line locates, safety watches, consumer consultations, building moves, and education and safety, apply to GSL customers. MIPUG argues that, since the $1.2 million in Customer Service costs do not apply to GSL customers, these costs should not be allocated to them.

Board Findings

The Board finds that costs in the Customer Service sub-category within the Customer Consultation and Information category should not be allocated to GSL 30-100kV or GSL>100kV customers unless and until Manitoba Hydro can provide a fulsome description of these costs. In this description, Manitoba Hydro shall:

- explain why these costs apply to the GSL classes,
- confirm that these costs are not already subsumed within the costs categorized as Key Accounts and Major Accounts, and

- justify why the customer weightings for the allocator, which provide greater weighting to GSL customers, are appropriate for these costs.

Allocation of Other Customer Services Costs

Manitoba Hydro's Position

Manitoba Hydro has agreed to update the customer weighting factors within its Customer Service allocators as time and resources allow.

Intervener Positions

The Coalition, GAC, and MIPUG each recommend that Manitoba Hydro update or provide additional support for various customer weightings. The allocation approach for these costs was not contentious in this proceeding and no intervener proposed alternative allocation methodologies.

Board Findings

The Board finds that, with the exception of the costs in the Customer Service sub-category of Customer Consultation and Information allocated to GSL >30kV classes, Manitoba Hydro's Customer Services allocators are appropriate for the allocation of Customer Services costs. The weightings used to allocate the Customer Services costs, such as for meter reading, billing, and collections, shall be updated.

12.0 Demand-Side Management

The Manitoba Hydro Power Smart programs are representative of energy efficiency, curtailable load (through the Curtailable Rate Program as explained in the Generation Allocation section of this Order) and other energy savings initiatives being conducted by utilities in North America. The general term within the industry that is used for these programs is demand-side management ("DSM"). DSM includes the activities that utilities engage in with the objective of reducing overall energy consumption, peak demand energy usage, or both, including providing rate tariffs (incentives) and customer services and information initiatives.

Expenditures that a utility makes to encourage more efficient electric energy consumption may include the following:

- Advertising – educational and program sales;
- Incentives to Customers – rebates and loans;
- Delivery costs – includes payments to trades and retailers, installation costs, program management, and administration;
- Measurement and Verification – efforts to estimate energy and capacity savings; and
- Overhead and Administrative – program planning and regulatory.

Expenditures also are made to discourage peak period consumption and lower the peak energy demand on the utility system. Examples of these expenditures are the following:

- Direct incentives paid for customer peak demand reductions;
- Revenue loss through special incentive pricing for peak demand reductions; and
- Overhead and Administrative – program planning and regulatory.

DSM investments reduce customer energy consumption and, in most instances, the peak demand of the Manitoba Hydro system. These reductions in energy consumption and peak demand can provide benefits to the Manitoba Hydro system by delaying Manitoba Hydro's investment in generation, transmission or distribution. These reductions in energy consumption and peak demand can also free up hydraulic generation for export, thus increasing export revenue. DSM investments were considered an alternative to generation in some of the plans evaluated in the recent Needs For and Alternatives To ("NFAT") review related to the proposed hydraulic generation additions of Keeyask and Conawapa.

Functionalization, Classification and Allocation of DSM Costs

Manitoba Hydro's Position

Manitoba Hydro directly assigns costs of each DSM program to the domestic classes participating in those programs. Manitoba Hydro then attributes the DSM energy savings to the participating classes in the load forecasts for each class. Where the costs of a DSM program apply to only one class, Manitoba Hydro assigns the costs to that class. Where DSM program activities support multiple classes, Manitoba Hydro allocates the costs to the applicable classes based on the class participation levels. Manitoba Hydro argues that this approach aligns the costs of DSM with the benefits, is less distorting to non-participating classes, and better matches the short term benefits with costs. While DSM does free up domestic load that can then be sold to exports, this is not the purpose for which the DSM programs were instituted. Manitoba Hydro submits that, since DSM is not driven by export sales and benefits the domestic classes through reduced load and allocations, DSM costs should be assigned to the customer classes benefiting from the DSM programming.

Intervener Positions

MIPUG supports Manitoba Hydro's direct assignment of the costs of DSM programs to participating classes as the most cost causal approach and most aligned with current system planning practices. MIPUG submits that, while it is appropriate in some jurisdictions to treat DSM as a system resource, it is not appropriate in Manitoba Hydro's case because there is no immediate benefit to Manitoba Hydro due to the current low export market prices. MIPUG states that cost responsibility for DSM should be placed on the classes that cause and influence the costs.

As a DSM program, the costs of the Curtailable Rate Program (CRP) are directly assigned to the GSL sub-classes that use the program. But since CRP benefits other classes by contributing to Manitoba Hydro's reserve capacity, Manitoba Hydro gives a credit to the CRP customer classes. The directly assigned costs of the CRP to the curtailable sub-classes, which is based on the revenue requirement of the CRP, exceeds this credit. MIPUG recommends that Manitoba Hydro adjust the credit to match the costs.

The Coalition disagrees with the approach of Manitoba Hydro and of MIPUG and argues that DSM is a system resource that benefits all customers, including those who participate and those who do not. The Coalition recommends that DSM costs should be assigned directly to the Generation, Transmission and Distribution functions based on the relative values of the DSM program savings in each area. The Coalition states that its recommended approach recognizes that DSM has a critical role in integrated least-cost resource system planning.

Similarly, Manitoba Keewatinowi Okimakanak ("MKO") disputes Manitoba Hydro's treatment of DSM costs and submits that DSM is a benefit to all Manitobans and provides for the opportunity for additional export revenue. MKO also notes that DSM has environmental benefits and other economic benefits, including job creation for Manitobans. MKO argues that its communities do not deliberately cause the circumstances that require DSM programs. Rather, the need for DSM is driven by geography, poor living conditions, and inadequate housing. Its communities also do not have access to the most reliable DSM program, which they state is fuel switching [from electricity to natural gas].

GAC suggests that the Board approach DSM from a policy position, such as treating DSM as a system resource. The Board should direct Manitoba Hydro to test the equity of the allocation by comparing the treatment of DSM as a system resource with directly assigning the costs of DSM to the participating classes. It argues that the most important consideration is to avoid causing harm to some classes while benefiting the system, while also minimizing tension among classes in the design of DSM programs.

GSS/GSM submits that DSM provides a public benefit of avoided system peak demand costs and therefore costs associated with DSM should be shared by all customers.

Board Findings

The Board finds that DSM costs should be functionalized as 100% Generation. DSM should be classified with the other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion and unweighted energy for the Energy portion. The Board finds that DSM is a Generation resource: it avoids Generation costs, rather than the costs of Transmission and Distribution. Within the customer classes, there are non-participants in DSM programs which support this approach over Manitoba Hydro's direct assignment of the costs.

Because DSM is treated as a system resource and the Curtailable Rate Program ("CRP") revenue requirement is no longer directly assigned to participating classes, there is no special treatment needed for the discrepancy between the revenue requirement cost of the CRP and the credit applied to the CRP customer classes.

DSM programs may appear similar to customer service programs such that the costs should be allocated or assigned to individual customer classes on a cost causation basis. The Board finds that, because DSM is a system resource, assigning DSM costs to individual classes is not warranted.

13.0 Other Matters

Area and Roadway Lighting

Manitoba Hydro owns and operates street lighting and sentinel area lighting on behalf of customers such as the City of Winnipeg and other municipalities. Street lights and sentinel lights are not metered; instead, the costs of these lights and the electricity they consume is charged based on the power each light consumes. Street lights, as the name implies, are the lighting along streets, roads, highways, in municipalities across Manitoba, including the City of Winnipeg. Sentinel lights are also known as security lights. Street lights can either be on a dedicated pole or can be on a pole that is shared with other utilities, such as telephone cables. The costs of the luminaires, wires, poles, whether the poles are dedicated or shared, and the number of hours the luminaires are expected to operate each year factor into the charges for Area and Roadway lighting.

Intervener Positions

The City of Winnipeg proposes that Manitoba Hydro split the Area and Roadway Lighting class into separate sub-classes of Street Lighting and Sentinel Lighting. The City of Winnipeg notes that bills for street lights usually have many street lights for each bill, while bills for sentinel lights usually have only one light. Manitoba Hydro counts each street light or sentinel light connection as a customer, even though there are many street light connections for each customer account or bill. As a result, the number of customers, which drives the allocation of customer-related costs, is inflated. Thus, the billing cost is overstated for street lighting and understated for sentinel lighting.

According to the City of Winnipeg, separating Street and Sentinel Lighting into separate sub-classes, and allocating billing costs in proportion to the number of bills issued, would result in a cost allocation more consistent with how customer costs are caused. Separate classes would also provide more detailed Revenue to Cost Coverage ratio information.

The City of Winnipeg argues that, absent splitting Area and Roadway Lighting into sub-classes for Street and Sentinel Lighting, Manitoba Hydro should recover billing costs through a fixed monthly charge that applies to each bill.

Manitoba Hydro's Position

Manitoba Hydro is able to differentiate revenue, energy, and demand between Street Lighting and Sentinel Lighting, but is not able to segregate over 70% of the costs between these sub-classes. As a result, to separate Street and Sentinel Lighting into sub-classes would require assumptions to prorate the total Area and Roadway Lighting costs between these sub-classes. Manitoba Hydro's view is that it is inappropriate to attempt to segregate $15 million of costs in order to more accurately allocate $263,000 of billing costs.

Board Findings

The Board finds that a single Area and Roadway Lighting class should continue and that the class should not be split into Street Lighting and Sentinel Lighting sub-classes. As Manitoba Hydro does not have cost data segregated by Street Lighting and Sentinel Lighting, arbitrary assumptions would be required to segregate the costs into sub-classes. With respect to adjusting the rate design by recovering billing costs through a fixed monthly charge, the Board finds that this is more appropriately addressed in a General Rate Application.

Late Payment Revenue and Customer Adjustments

Late payment revenue is collected from customers in the form of interest on overdue accounts. Customer adjustments relate to miscellaneous charges that include inspection fees, disconnection and reconnection fees, federal meter disputes, and special meter read fees.

Manitoba Hydro's Position

In PCOSS14 Amended, late payment revenue is allocated among the classes based on each class's proportion of unadjusted class revenue. Manitoba Hydro agrees with the Coalition's proposal, as set out below.

Intervener Positions

The Coalition recommends that late payment revenues be allocated based on the historical proportion of late payment revenues collected from each class. The Residential class pays more than 80% of the late payment revenue, but under Manitoba Hydro's methodology, is only allocated 51% of this revenue.

Board Findings

The Board finds that late payment revenue and customer adjustments should be allocated based on the share of late payment revenue that was collected from each respective class. Late payment revenues can be directly attributed to the classes from which they arise and comprise the majority of the late payment and customer adjustment costs.

Common Costs

Common costs include general and administrative costs such as buildings, communication systems, control systems, general equipment, human resources, and payroll.

Functionalization of Common Costs

Manitoba Hydro's Position

In PCOSS14 Amended, common costs are functionalized to Generation, Transmission, Subtransmission, Distribution, and Customer Services according to an internal labour allocator. The labour allocator is based on Manitoba Hydro's operating costs net of power purchases, fuel, and water rental charges.

Buildings and General common costs are functionalized by the labour allocator. For Communication and Control costs, the labour allocator is calculated without any Customer Services costs; therefore, the labour allocator does not functionalize any costs to the Customer Services function. Supervisory Control and Data Acquisition ("SCADA") costs, which arise from the data monitoring of Manitoba Hydro's system, are functionalized to Generation, Transmission, and Subtransmission in a 36/28/36 proportion. Manitoba Hydro intends to review this 36/28/36 factor as time and resources allow.

With respect to Coalition's recommendation to reassess the sub-functionalization of Communication operating and depreciation costs that are functionalized as Distribution, Manitoba Hydro indicates that it has completed this work and it will be included in the next PCOSS. Manitoba Hydro has also completed updates to its COSS model to include the sub-functionalization of common costs within the model.

Intervener Positions

The Coalition identifies an inconsistent treatment of interest, operating, and depreciation costs in the sub-functionalization of Distribution common costs. For example, Communication plant operating and depreciation costs functionalized as Distribution are further sub-functionalized as Stations, but the Communications assets are sub-functionalized as poles and wires which means the interest costs are also sub-functionalized as poles and wires. The Coalition recommends that Manitoba Hydro reassess the sub-functionalization.

Board Findings

The Board finds that Manitoba Hydro's Buildings and General common costs are to be functionalized across all functions using Manitoba Hydro's labour allocator. Communication and Control common costs should be functionalized by the labour allocator, with no allocations to the Customer Services function as proposed by Manitoba Hydro, and the SCADA allocator. Manitoba Hydro shall update the 36/28/36 factors for SCADA functionalization as Manitoba Hydro currently has no evidence to support it and it has not been updated since 1997. The Coalition's recommendation on the sub-functionalization of Distribution common costs is addressed in the following section.

Allocation of Common Costs

Manitoba Hydro's Position

Manitoba Hydro allocates common costs that are functionalized as Generation, Transmission, or Subtransmission to the customer classes by the principal allocator for each function (for example, Generation common costs are allocated by Weighted Energy). Manitoba Hydro's proposed methodology for allocating common costs functionalized as Distribution is to allocate them on the same basis as distribution poles and wires in order to reflect both a Demand and Customer classification. Common costs functionalized as Distribution are allocated using the distribution poles and wires allocator, which allocates 60% (the Demand portion) by Non-Coincident Peak and 40% (the Customer portion) by unweighted customers. Common costs functionalized as Customer Services are allocated based on a cost-weighted average of all allocators used to allocate customer service expenses. Manitoba Hydro proposes the weighted energy allocator for all Generation costs.

Intervener Positions

The issue of the allocation of common costs was not contentious in this proceeding and the interveners did not put positions forward.

Board Findings

The Board finds that common costs within each function should be allocated to customer classes based on the cost-weighted average of all the allocators within each function. As a result of changes directed by the Board in this Order, the methodology proposed by Manitoba Hydro for allocating common costs within each function is no longer valid.

First, as found above, the classification of poles and wires should be 100% Demand, rather than Manitoba Hydro's Demand and Customer classification. The Board finds that there is a Customer aspect to Distribution common costs, therefore allocating these costs on same basis as poles and wires is rejected.

Second, as this Order directs changes to the allocation methodologies for Generation and Transmission, there is no longer a single allocator for each function. The Board finds that there are different allocators for the Energy and Demand classified costs. Common costs assigned to each function should be allocated by the cost-weighted average of the allocators within each function.

Allocating Distribution common costs on the basis of the weighted average of all Distribution function allocators means there is no need to sub-functionalize the Distribution common costs to particular sub-functions. This addresses the Coalition's recommendation for Manitoba Hydro to review its sub-functionalization of Distribution common costs.

The Board views this direction as interim. Improved information is needed and Manitoba Hydro is directed to study the allocation of common costs and develop allocators that are more directly related to the causes of the common costs.

14.0 Compliance Filing

In this Order, the Board has adjudicated the issues that relate to the methodology that Manitoba Hydro is to employ when it prepares its next COSS or PCOSS. The Board directs Manitoba Hydro to file its next COSS in conjunction with Manitoba Hydro's next General Rate Application ("GRA").

In the interim, and utilizing the methodology approved by the Board in this Order and summarized in Appendix B, the Board directs Manitoba Hydro to make a compliance filing within 60 days of the date of this Order. This filing will be a revised version of PCOSS14 Amended that reflects all of the Board's findings and directions in this Order. To better demonstrate that the Board's directions from this Order are captured in the compliance filing, Manitoba Hydro shall file its revised electronic model and the results for Board approval.

The Board notes that the sharing of the electronic COSS models greatly enhanced the participation by and understandings of Interveners and their experts. Manitoba Hydro shall therefore include in its next GRA filing an electronic version of its COSS model, as revised to comply with the Board's directives in this Order.

15.0 IT IS THEREFORE ORDERED THAT:

1. Manitoba Hydro's Cost of Service Study methodology shall be revised and updated as directed in this Order as follows:

    (a) An Export class shall not be used in the COSS;

    (b) Export revenue shall be credited to the domestic classes based only on each class's share of total Generation and Transmission costs;

    (c) The following costs shall be deducted from gross export revenues:

        (i) Energy costs for water rentals associated with exports

        (ii) Variable hydraulic operating and maintenance costs associated with exports

        (iii) The costs of the Affordable Energy Fund

    (d) The costs of the Uniform Rate Adjustment shall not be deducted from export revenue;

    (e) Export revenues shall not be credited to the Diesel class;

    (f) Costs that shall be functionalized as Generation are as follows:

        (i) Manitoba Hydro's hydraulic and thermal generating stations, including operations and maintenance, fuel, and water rental costs;

        (ii) The costs related to wind energy purchases and import purchases;

        (iii) The following generation outlet transmission facilities: the Northern Collector System, the northern converter stations Henday, Radisson, and Keewatinohk, Wuskwatim generating station to Wuskwatim switchyard 230kV lines, St. Leon wind farm 230kV lines, St. Joseph wind farm

230kV lines, Pointe du Bois-Rover 66kV lines, Slave Falls-Pointe du Bois 115kV lines, and Pointe du Bois switching station;

(iv) Bipoles I, II, and III;

(v) The HVDC portions of the Dorsey and Riel converter stations; and

(vi) DSM costs;

(g) Wind purchases, water rentals and variable hydraulic operation and maintenance costs shall be classified as 100% Energy. All other Generation costs shall be classified as both Energy and Demand, with the proportions determined by the system load factor method. The system load factor shall be based on multi-year historical domestic load data and updated for each PCOSS;

(h) Generation costs classified as Energy shall be allocated on the basis of unweighted energy;

(i) Generation costs classified as Demand shall be allocated by the top 50 Winter Coincident Peak hours of the domestic customer classes;

(j) The domestic AC transmission system operating at voltages greater than 100kV, interprovincial interconnections, and U.S. interconnections shall be functionalized as Transmission;

(k) The domestic AC transmission system operating at voltages greater than 100kV and interprovincial interconnections shall be classified as 100% Demand and allocated on the basis of Winter Coincident Peak;

(l) The U.S. interconnections shall be classified on the basis of system load factor, with the Demand portion allocated on the basis of Winter Coincident Peak and the Energy portion on the basis of unweighted energy;

(m) The cost of radial taps shall be directly assigned to the GSL >100kV customer class;

(n) The Subtransmission function shall remain a separate function from Transmission, encompassing transmission assets less than 100kV but greater than or equal to 33kV;

(o) Subtransmission shall be classified as 100% Demand and allocated by Winter Coincident Peak;

(p) Assets that operate below a voltage of 33kV, including poles, wires, the low voltage side of substations, meters, and distribution transformers shall be functionalized as Distribution;

(q) Distribution poles and wires shall be classified as 100% Demand;

(r) The costs of distribution substations and distribution transformers shall be classified as 100% Demand;

(s) Service drops, meter investment, and meter maintenance shall be classified as 100% Customer;

(t) The Demand component of Distribution costs shall be allocated based on each class's Non-Coincident Peak;

(u) The Demand factor for the GSL 0-30kV class for distribution poles and wires shall be reduced by 30%;

(v) Manitoba Hydro shall update its Service Drops cost allocator including revisiting the weightings for GSS, GSM, and GSL 0-30kV 3-phase services. In the interim, the allocation methodology shall prorate the 103,000 Residential customers over the three classes based on the number of customers in each class;

(w) Manitoba Hydro shall update its Customer-related allocators and weighting factors for its Distribution costs that are Customer classified, including the weightings for meter investment and meter maintenance;

(x) Costs related to serving and communicating with customers after delivery of energy, including meter reading, billing, collections, information and customer assistance, advertising, sales, sections, research and development, rates and cost of service, load research, and other departmental costs such as Power Smart Energy Services, shall be functionalized and classified as Customer Services;

(y) The costs in the Customer Service sub-category within the Customer Consultation and Information category shall not be allocated to GSL 30-100kV or GSL >100kV customers, unless and until Manitoba Hydro can provide a fulsome description of these costs. With the exception of the costs in this sub-category, Manitoba Hydro's Customer Services allocators are appropriate;

(z) The weightings used to allocate the Customer Services costs shall be updated;

(aa) A single Area and Roadway Lighting class shall continue;

(bb) Late payment revenue and customer adjustments shall be allocated based on the share of late payment revenue that was collected from each respective class;

(cc) Buildings and General common costs shall be functionalized across all functions using Manitoba Hydro's labour allocator;

(dd) Communication and Control common costs shall be functionalized by the labour allocator and the SCADA allocator;

(ee) Manitoba Hydro shall update the 36/28/36 factors for functionalization of SCADA common costs;

(ff) Common costs within each function shall be allocated to customer classes based on the cost-weighted average of all the allocators within each function;

(gg) Manitoba Hydro shall study the allocation of common costs and develop allocators that are more directly related to the causes of the common costs; and

(hh) DSM costs shall be functionalized as 100% Generation, classified as Energy and Demand based on system load factor, and allocated on Winter Coincident Peak for the Demand portion and unweighted energy for the Energy portion. No special treatment is needed for the discrepancy between the revenue requirement cost for the Curtailable Rate Program ("CRP") and the credit applied to the CRP customer classes;

2. Manitoba Hydro shall provide a compliance filing within 60 days of this Order. The compliance filing by Manitoba Hydro shall be a revised version of PCOSS14 Amended that reflects all of the Board's findings and directions in this Order. The compliance filing shall include Manitoba Hydro's electronic model together with the results;

3. Manitoba Hydro shall file, with its next General Rate Application, a new Prospective Cost of Service Study that shall be prepared using the methodology approved in this Order; and

4. Manitoba Hydro shall include, in its next General Rate Application filing, an electronic version of its COSS model, as revised to comply with the Board's directives in this Order.

Unless otherwise specified in this Order, the directives in this Order are effective at the time of pronouncement.

Should there be any inconsistencies among the body of this Order, Appendix B and the directives in section 15.0 of this Order, section 15.0 shall prevail.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure. The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

THE PUBLIC UTILITIES BOARD

"MARILYN KAPITANY, B.Sc. (Hon), M.Sc.,"
Acting Chair

"KURT SIMONSEN"
Acting Secretary

Certified a true copy of Order No. 164/16 issued by The Public Utilities Board

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Acting Secretary

APPENDIX A: GLOSSARY OF COSS TERMS

Cost-of-Service Acronyms

Term	Acronym	Description
1 Seasonal Coincident Peak	1CP	An allocation factor based on each customer class's average electricity demand during either the top coincident load hour(s) in the winter or the top coincident load hour(s) in the summer (Manitoba Hydro uses top 50 hours). Also often referred to as Winter Coincident Peak or Summer Coincident Peak.
2 Coincident Peaks	2CP	An allocation factor based on each customer class's average electricity demand during both the top coincident load hour(s) in the winter and the top coincident load hour(s) in the summer (Manitoba Hydro uses top 50 hours).
Affordable Energy Fund	AEF	A fund established in 2006 by the Province of Manitoba (through *The Winter Heating Cost Control Act*) that required Manitoba Hydro to set aside 5.5% of its fiscal 2006/07 gross export revenues to be utilized for various energy efficiency initiatives throughout Manitoba. Approximately $19 million of the AEF's $36.8 million was earmarked for assistance to low-income electricity and natural gas customers.
alternating current	AC	Alternating current is an electric current in which the flow of electric charge reverses direction 60 times per second (60 Hertz or 60 Hz), whereas in direct current (DC, also dc), the flow of electric charge is only in one direction. AC is the form in which electric power is delivered to businesses and residences.
Area and Roadway Lighting	A&RL	Applies to general outdoor lighting equipment used to illuminate roadways as well as private or public areas on a dusk-to dawn basis throughout the Province of Manitoba. The A&RL customers are typically municipal entities such as municipal corporations, local government districts, Provincial and Federal Governments.
Bipole		An electrical power transmission line, within a HVDC system, having two direct-current (DC) conductors in opposite polarity. A bipolar scheme can be implemented so that the polarity of one or both poles can be changed. This allows the operation as two parallel monopoles. If one conductor fails, transmission can still continue at reduced capacity on the other pole.
Christensen Associates		Manitoba Hydro's consultant providing advice on cost of service matters.

Term	Acronym	Description
City of Winnipeg		An Intervener: The City of Winnipeg is the single largest consumer of electricity in Manitoba Hydro's Area and Roadway Lighting customer class. Furthermore, the City of Winnipeg also operates several properties which fall in the General Service category.
Coalition		The Consumers Coalition, or Coalition, is an intervener in the COSS proceeding. The Coalition is comprised of the Consumers Association of Canada (Manitoba) and Winnipeg Harvest.
Coincident Peak	CP	Coincident peak is a measure of each customer class's contribution to system peak demand at the same hour of system peak.
Conawapa		A hydroelectric generating station proposed by Manitoba Hydro. Conawapa was considered by the Board in 2014 during its Needs For and Alternatives To review of Manitoba Hydro's Preferred Development Plan. The Board recommended that Conawapa not proceed.
Consumers' Association of Canada	CAC	An Intervener: CAC seeks to represent the interests of Manitoba Hydro's residential ratepayers. CAC has over 400 members and donors, and has had contact with approximately 14,000 consumers through education and consumer research. In recent Manitoba Hydro regulatory proceedings, CAC partnered with Winnipeg Harvest to form the Consumer Coalition to represent the interests of urban and rural residential consumers through evidence based advocacy.
converter station		A high voltage direct current (HVDC) converter station is a specialized type of substation which forms the terminal equipment for a HVDC transmission line. Converter station equipment converts alternating current to direct current, or the reverse. Manitoba Hydro currently operates, or has in construction, three northern converter stations (Henday, Radisson, and Keewatinohk) to convert alternating current (AC) collected from nearby generating stations to direct current (DC) power for transmission to southern Manitoba. As well, Manitoba Hydro operates, or has in construction, two southern converter stations (Dorsey and Riel) to convert DC to AC for downstream customer transmission and distribution.
Cost of Service Study	COSS	A process undertaken to determine the responsibilities that each customer class has for Manitoba Hydro's total revenue requirement. The purpose is to allocate a utility's costs to the various classes of customers that it serves.

Term	Acronym	Description
Curtailable Rate Program	CRP	A program offered to Manitoba Hydro's industrial customers that gives credits on the customer bills in exchange for commitments to curtail their load during times of system emergencies.
"Customer" cost classification		Utility costs that tend to vary with the number of customers. These would include asset costs such as meters and service drops, as well as billing, meter reading, and customer service costs.
Customer Services (functionalization)		Costs associated with service provided to the customer after delivery of energy.
"Demand" cost classification		Utility costs that tend to vary with the peak electricity usage as opposed to average usage or usage over a period of time.
demand-side management	DSM	A common utility strategy for reducing consumer demand (frequently through energy efficiency measures) for energy in order to defer the need for new generation assets. Manitoba Hydro's DSM plan, marketed under the Power Smart brand, involves various education and incentive programs aimed to reduce domestic consumption of both electrical and natural gas.
dependable energy		Energy that can be produced by Manitoba Hydro even during drought conditions, and is based on water levels and flows experienced in the lowest water flow year on record. This includes the minimum expected generation from the hydraulic generating stations plus continuous operation of the Selkirk and Brandon thermal generating stations, plus the minimum expected wind generation from St. Leon and St. Joseph, plus contracted imports.
dependable sales		Export sales made from dependable energy resources. These are also referred to as firm sales.
Diesel class		Customers in four northern remote communities (Shamattawa, Brochet, Lac Brochet, and Tadoule Lake) are not connected to Manitoba Hydro's transmission grid and are served by local diesel-fuelled generators. The customers in these four communities comprise the Diesel class. The Diesel class has its own prospective cost of service and rate design, separate from the COSS for the interconnected transmission grid.
Distribution (functionalization)		Utility assets used to distribute lower voltage electricity to individual customers. Manitoba Hydro functionalizes all distribution lines operating at voltages less than 33kV (with associated low voltage portions of substations), as well as low voltage transformers and metering, as Distribution in its PCOSS.

Term	Acronym	Description
embedded Cost of Service Study	embedded COSS	Embedded cost of service studies are backward looking and consider the costs of a utility's plant that is already in service. Embedded cost studies are based on revenue requirement analyses that examine average costs. Embedded cost of service studies differ from marginal cost of service studies which refer to the cost of adding an incremental amount of load to a utility system.
"Energy" cost classification		Utility costs that vary with the consumption of electricity.
equivalent peaker		A cost of service methodology used to help determine the classification of generation assets. Generators provide both demand and energy, but the classification is not always clearly defined. The equivalent peaker method estimates the cost of an equivalent peaking generator, which is typically a single cycle gas turbine because it is the least expensive generator that can provide capacity (i.e. respond to peak demand). It then considers the cost of the alternative generator (e.g. hydroelectric, coal, etc.) and assumes the ratio of the alternative generator's cost to the equivalent peaker's cost is the same as the ratio of the energy to demand classification.
Export class		A customer class within the cost of service study that tracks the volumes of exported electricity, the corresponding export revenues, and allocations of costs, predominantly Generation and Transmission costs.
feeder		In a power distribution system, an electric feeder is a set of electric conductors that originate at a substation and supply power to one or more secondary distribution centers, branch-circuit distribution centers, or a combination of these.
General Rate Application	GRA	A Public Utilities Board process to review Manitoba Hydro's proposed changes to electrical or gas rates and their impacts on various customer groups.
General Service Large	GSL	A customer class containing predominantly industrial customers. These customers make use of customer-owned voltage transformation assets. This customer class is divided into three sub-categories, 0-30kV, 30-100kV, and >100kV, to reflect the customer's end supply voltage.
General Service Medium	GSM	A customer class containing predominantly large commercial customers. These customers use Manitoba Hydro-owned transformation assets exceeding ~200kW.

Term	Acronym	Description
General Service Small	GSS	A customer class containing predominantly small commercial customers with loads less than ~200kW. This customer class is divided into two sub-categories, Demand and Non-Demand. Demand customers pay a Demand rate based on the peak demand each month, in addition to a basic monthly charge and an energy (per kWh) charge.
Generation (functionalization)		Utility assets used to generate electricity. Manitoba Hydro functionalizes all generating facilities, northern collector circuits, and HVDC facilities as generation in its PCOSS.
generation outlet transmission		Electrical conductors, and related switching and control equipment, linking electrical generators to transmission substations or converter stations.
Green Action Centre	GAC	An intervener: A non-profit organization governed by an elected community board and committed to advancing applied sustainability. Green Action Centre's mission is to promote greener and better living by sharing practical solutions and advocating for change. GAC's primary areas of work are green commuting, composting and waste, sustainable living, resource conservation, and energy and climate change policy.
grid		The interconnected electric transmission and distribution system, including networked transmission, radial transmission, and distribution. Customers connected to the grid receive electricity generated by Manitoba Hydro's predominantly hydraulic generating system.
General Service Small / General Service Medium	GSS/GSM	An intervener: Represents the interest of the small and medium-sized commercial users of electricity in Manitoba falling into the General Service Small and General Service Medium categories.
high-voltage direct current	HVDC	An electric power transmission system that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems. HVDC transmission is point-to-point, as opposed to the interlaced networks that are possible with AC systems. For long-distance transmission, HVDC systems may be less expensive and experience lower electrical losses.
interconnection		The physical linking of a utility's electrical network with equipment or facilities not belonging to that network. The term may refer to a connection between a utility's facilities and the equipment belonging to its customer, or to a connection between two (or more) utilities.

Term	Acronym	Description
Integrated Financial Forecast	IFF	Provides projections of Manitoba Hydro's financial results and position over a 20-year period (e.g.: IFF15 covers the period from 2015/16 to 2034/35). The IFF serves as the primary forecast to determine the need for rate increases that are necessary for Manitoba Hydro to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets.
Keeyask		Manitoba Hydro’s newest hydraulic generating station under construction on the Nelson River. It is projected to enter service as early as 2019/20.
kilovolt	kV	An amount of electromotive force equivalent to 1,000 volts (V).
kilowatt	kW	An amount of electrical power equivalent to 1,000 watts (W).
kilowatt-hour	kWh	The basic unit of electric energy equal to one kilowatt of power supplied to, or taken from, an electric circuit steadily for one hour (e.g.: ten 100 W lightbulbs left on for 1 hour would use 1 kWh, or 1000 W for one hour). A typical home without electric heat uses about 10,000 kWh each year.
Manitoba Industrial Power Users Group	MIPUG	An intervener: Represents the interest of the largest industrial users of electricity in Manitoba falling into the General Service Large >30kV categories. Collectively, MIPUG members purchase in excess of 5,000 GWh per year of electricity, which approximates 25% of Manitoba Hydro's domestic sales. MIPUG members have a long track record of operation and investment in Manitoba. MIPUG works on electricity supply and rate issues for its members.
Manitoba Keewatinowi Okimakanak	MKO	An intervener: A non-profit advocacy organization representing approximately 65,000 Treaty First Nation citizens in Northern Manitoba. MKO is governed by elected Chiefs of the 30 sovereign First Nations in Northern Manitoba. MKO notes that its mission is to maintain, strengthen, enhance, lobby for and defend the interests and rights of First Nation peoples within its jurisdiction and to promote, develop and secure a standard and quality of life deemed desirable and acceptable by its member First Nations.

Term	Acronym	Description
Manitoba Metis Federation	MMF	An intervener: The Manitoba Metis Federation is the official democratic and self-governing political representative for the Métis Nation's Manitoba Métis Community. The mandate of the MMF is to promote the social and economic interests of its members and to participate in the consideration of issues that affect its members. In Manitoba Hydro's regulatory proceedings, the MMF represents the interests of Manitoba's Métis community, which involves both residential and small business customers.
marginal Cost of Service Study	marginal COSS	Marginal cost of service studies are forward looking and consider the cost of plant to be added in the future. Marginal cost of service studies differ from embedded cost of service studies which refer to a utility's average historical cost of plant.
Midcontinent Independent System Operator	MISO	A regional electricity transmission organization that assures unbiased regional grid management and open access to the transmission facilities. MISO serves as a link in the safe, reliable, and cost-effective delivery of electric power across all or parts of 15 U.S. states and the Canadian province of Manitoba. It is the principal market that Manitoba Hydro exports power to.
National Association of Regulatory Utility Commissioners	NARUC	A non-profit organization dedicated to representing the public service commissions of all U.S. states. Its mission is to serve in the public interest by improving the quality and effectiveness of public utility regulation. NARUC publishes a Cost of Service manual that is a standard reference for cost of service studies.
National Energy Board	NEB	Federal regulator for international electricity exports and imports. In the COSS context, there are fees paid to the NEB for permits to import or export energy.
Needs For and Alternatives To	NFAT	Extensive review of Manitoba Hydro's Preferred Development Plan by the PUB with final recommendations made to the Province of Manitoba as to which development option should proceed. An NFAT was last undertaken in 2014 to review Manitoba Hydro's Keeyask, Conawapa, US Intertie, and expanded DSM project investments.
Net Export Revenue	NER	In the context of the COSS, net export revenue is the residual export revenue after deducting costs allocated to the Export class. In Manitoba Hydro’s PCOSS, NER is credited to each customer classes based on the proportionate share of the total Generation, Transmission and Distribution costs allocated to each domestic class.

Term	Acronym	Description
networked transmission		A system of interconnected electrical transmission lines that connect the electricity generators with consumers. Redundant power lines in networked transmission minimize the probability of grid instability and failure. The alternative transmission configuration is radial transmission.
Non-Coincident Peak	NCP	Non-coincident peak assesses the maximum demand of each customer class regardless of when it occurs. That is, each class has its own peak demand, but they may not occur at the same time as other classes' peak demand.
Non-Tariffable Transmission		A sub-function in Manitoba Hydro's cost of service study that captures the costs of transmission lines and substations that are not eligible to be included in Manitoba Hydro's Transmission Tariff (also known at Open Access Transmission Tariff or OATT) that is charged to third parties using Manitoba Hydro's transmission system. Non-tariffable transmission includes radial taps that exclusively serve domestic customers.
off-peak		Off-peak refers to lower electricity prices that are generally expected when power is delivered during periods of low electricity usage. Manitoba Hydro's off-peak periods are defined as all night time hours from 11pm to 7am.
on-peak		On-peak refers to higher electricity prices that are generally expected when power is delivered during periods of high electricity usage. Manitoba Hydro's on-peak periods are defined as Monday to Friday (excluding Statutory Holidays) 12pm-8pm (May-October), as well 7am-11am and 4pm-8pm (November-April).
Open Access Transmission Tariff	OATT	A tariff charged to parties wishing to use transmission facilities. Under an OATT, transmission users receiving non-discriminating service comparable to that provided by Transmission Owners to themselves. The OATT is based on cost recovery, with only costs related to facilities that could be used by the transmission users included. Manitoba Hydro has an OATT that can be used, for example, by parties wishing to transmit power from MISO to Saskatchewan through Manitoba.
opportunity sales		Export sales made from surplus generation, typically hydraulic generation that is available in most water flow conditions except drought conditions.
primary voltage		Voltage greater than 750V.

Term	Acronym	Description
Prospective Cost of Service Study	PCOSS	An embedded cost of service study in that it is based on forecast financial costs for a single test year period from the Integrated Financial Forecast. PCOSS14 refers to the PCOSS with a test year of 2013/14, which is based on IFF12, the IFF approved in 2012.
radial taps		Radial taps are generally groups of conductors (and related assets) feeding high voltage power, carried by the utility's transmission assets, directly to customers, typically large industrial users. Power delivered via radial taps typically does not make use of utility-owned subtransmission facilities.
radial transmission		Radial transmission refers to non-redundant power lines that connect the electric grid with consumers. That is, there is only one path for electricity to flow to reach a consumer or group of consumers. The alternative transmission configuration is networked transmission.
rate design		The process of determining the rates charged to each customer class. The cost of service study is a tool that may be used in rate design. Rates for each customer class can have basic monthly charges, demand charges, and energy rates, or a subset of these three charges.
Residential class		A customer class in Manitoba Hydro’s rate or tariff structure. The Residential class includes the costs to serve and the revenues from residential customers throughout Manitoba, including seasonal customers (e.g. cottages) and flat rate water heating (where Manitoba Hydro charges a flat rate based on the size of the heating element in the water heater).
Revenue to Cost Coverage	RCC	The ratio of revenues received from a class to the costs allocated to a class. Generally, the objective is to obtain a RCC of 1 (or 100%) for each customer class, or within a range called the zone of reasonableness.
secondary voltage		Voltage less than or equal to 750V.
Sentinel Lighting		Sentinel lights are also known as security lights and include the costs of luminaires, poles, and wires. The costs of sentinel lights are affected by the size of the luminaire and the number of hours the luminaires are expected to operate each year.
service drops		Service drops, also known as services, are wires that connect individual homes and businesses to either the primary or secondary voltage systems, and can be either above ground to a mast on the building or underground to the meter.

Term	Acronym	Description
single cycle combustion turbine	SCCT	A gas turbine engine powered by natural gas or diesel fuel that drives an AC generator to produce electricity. SCCTs are typically used during peak periods only because they are less efficient than CCCTs but they are lower capital cost.
Street Lighting		A sub-category of Area and Roadway Lighting, street lighting refers to the lighting along streets, roads, highways, in municipalities across Manitoba, including the City of Winnipeg. Street lighting includes the costs of luminaires, wires, and poles. The costs of street lights are affected by the size of the luminaire, whether the luminaire is affixed to a dedicated pole or to a pole that is shared with other utilities, such as telephone cables, and the number of hours the luminaires are expected to operate each year.
substation		Substations are facilities in the electrical generation, transmission, and distribution system, and generally transform voltage from high to low (or the reverse), as well as provide switching control of the electric system. A substation may include transformers to change voltage levels between high transmission voltages and lower distribution voltages, or at the interconnection of two different transmission voltages. Manitoba Hydro operates multiple substations in order to serve the various voltage levels required by its customers.
Subtransmission (functionalization)		Utility assets – such as towers, wires, and substations – used to transmit electricity between the Transmission system and load centres. Manitoba Hydro functionalizes all 33kV and 66kV transmission lines and low voltage portions of substations as Subtransmission in its PCOSS.
Summer Coincident Peak		An allocation factor based on each customer class's average electricity demand during the top coincident load hour(s) in the summer (Manitoba Hydro uses top 50 hours). Also referred to as 1 Seasonal Coincident Peak.
Surplus Energy Program	SEP	The Surplus Energy Program is a Manitoba Hydro rate program that enables a qualifying customer to purchase surplus energy at export market prices that are determined on a weekly basis for peak, shoulder, and off-peak periods, if and when Manitoba Hydro has surplus energy to sell.
system load factor		System load factor is the average demand divided by peak demand. In a COSS methodology, it is a method of classifying costs as Energy and Demand. A higher system load factor classifies more cost as Energy; conversely a lower load factor classifies more cost as Demand.

Term	Acronym	Description
Tariffable Transmission		A sub-function in Manitoba Hydro's cost of service study that captures costs of transmission lines and substations that are eligible to be included in Manitoba Hydro's Transmission Tariff (also known at Open Access Transmission Tariff or OATT) that is charged to third parties using Manitoba Hydro's transmission system.
Transmission (functionalization)		Utility assets used to transmit electricity between generating stations and load centres. Manitoba Hydro functionalizes all transmission lines and high voltage portions of substations operating at voltages in excess of 100kV as Transmission in its PCOSS.
Uniform Rate Adjustment	URA	In 2001, legislation mandated uniform rates in Manitoba (also known as "postage stamp rates"). Previously, residential customers in Northern Manitoba and in rural areas paid higher rates than those in Winnipeg. The higher Northern and rural rates were reduced to the Winnipeg rates. The loss of revenue was charged to export sales and is reflected as a direct assignment to the Export class, reducing net export revenue by $24 million in PCOSS14.
volts	V	An amount of electromotive force or electric potential. Typical household wiring operates at 120 volts.
water rentals		Fees paid by Manitoba Hydro to the Provincial Government based on the amount of electricity produced from hydraulic generation.
Winter Coincident Peak	WCP	An allocation factor based on each customer class's average electricity demand during the top coincident load hour(s) in the winter (Manitoba Hydro uses top 50 hours). Also referred to as 1 Seasonal Coincident Peak.
zone of reasonableness		An established tolerance zone around the RCC target of 100% for each class. Manitoba Hydro's Zone of Reasonableness is for RCCs to be within the range of 95% to 105%. A ratio outside of the Zone of Reasonableness is one factor to be considered when setting customer rates which may lead to some classes receiving a higher or lower rate increase than other classes.

APPENDIX B: SUMMARY OF TREATMENT OF ASSETS AND COSTS

Functionalization	Classification	Allocation
Generation		
hydraulic and thermal generating stations	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
generation outlet transmission facilities, including: • Northern Collector System • Henday, Radisson, and Keewatinohk converter stations • Wuskwatim generating station to Wuskwatim switchyard 230kV lines • St. Leon wind farm 230kV lines • St. Joseph wind farm 230kV lines • Pointe du Bois-Rover 66kV lines • Slave Falls-Pointe du Bois 115kV lines • Pointe du Bois switching station	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
import purchases	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
Bipoles I, II, and III	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
HVDC portions of the Dorsey and Riel converter stations	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
demand-side management (DSM)	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
MISO fees, transmission fees, NEB fees	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy

Functionalization		Classification	Allocation
	water rentals and variable hydraulic operation and maintenance costs	100% Energy	unweighted energy
	wind purchases	100% Energy	unweighted energy
Transmission			
	domestic AC transmission system operating at voltages greater than 100kV	100% Demand	Winter Coincident Peak
	interprovincial interconnections	100% Demand	Winter Coincident Peak
	U.S. interconnections	system load factor	Demand: Winter Coincident Peak Energy: unweighted energy
	radial taps	-	direct assign to the GSL >100kV customer class
Subtransmission			
	transmission assets less than 100kV but greater than or equal to 33kV	100% Demand	Winter Coincident Peak
Distribution (assets that operate below a voltage of 33kV)			
	distribution substations	100% Demand	Non-Coincident Peak
	distribution poles and wires	100% Demand	Non-Coincident Peak Demand factor for GSL 0-30kV class shall continue to be reduced by 30%
	distribution transformers	100% Demand	Non-Coincident Peak

Functionalization		Classification	Allocation
	service drops, meter investment, and meter maintenance	100% Customer	weighted customers Manitoba Hydro shall update its Service Drops cost allocator including revisiting the weightings for GSS, GSM, and GSL 0-30kV 3-phase services. In the interim, the allocation methodology shall prorate the 103,000 Residential customers over the three classes based on the number of customers in each class. Manitoba Hydro shall update Customer weightings including for meter investment and meter maintenance
Customer Services			
	Costs related to serving and communicating with customers after delivery of energy, including: meter reading, billing, collections, information and customer assistance, advertising, sales, sections, research and development, rates and cost of service, load research, and other departmental costs such as Power Smart Energy Services	100% Customer	weighted customers as proposed by Manitoba Hydro Manitoba Hydro shall update the weightings The costs in the Customer Service sub-category within the Customer Consultation and Information category are not to be allocated to GSL 30-100kV or GSL >100kV customers, unless and until Manitoba Hydro can provide a fulsome description of these costs.

Other Issues	
	A single Area and Roadway Lighting class shall continue.
	Late payment revenue and customer adjustments shall be allocated based on the share of late payment revenue that was collected from each respective class.
	Buildings and General common costs shall be functionalized across all functions using Manitoba Hydro's labour allocator.
	Communication and Control common costs shall be functionalized by the labour allocator and the SCADA allocator.
	Manitoba Hydro shall update the 36/28/36 factors for functionalization of SCADA common costs.
	Common costs within each function shall be allocated to customer classes based on the cost-weighted average of all the allocators within each function.
	Manitoba Hydro shall study the allocation of common costs and develop allocators that are more directly related to the causes of the common costs.
Treatment of Export Revenue	
	An Export class shall not be used.
	Export revenue shall be credited to the domestic classes based only on each class's share of total Generation and Transmission costs.
	The following costs shall be deducted from gross export revenues prior to crediting to domestic classes: • per kilowatt-hour energy costs for water rentals associated with exports; • variable hydraulic operating and maintenance costs associated with exports; • the Affordable Energy Fund. The costs of the Uniform Rate Adjustment shall not be deducted from gross export revenue.

APPENDIX C: APPEARANCES

PARTY	LEGAL COUNSEL
The Public Utilities Board	Bob Peters, Sven Hombach, Dayna Steinfeld
Manitoba Hydro	Odette Fernandez, Janelle Hammond, Marla Boyd, Patricia Ramage
Consumer Coalition	Byron Williams, Alex Nisbit
General Service Small & General Service Medium Representative	Christian Monnin, Michael Weinstein
Green Action Centre	Bill Gange, David Cordingley
Manitoba Industrial Power Users Group	Antoine Hacault
Manitoba Keewatinowi Okimakanak Inc.	George Orle Q.C.
Manitoba Metis Federation	Jessica Saunders, Terrance Delaronde
Winnipeg (City of)	Denise Pambrun

APPENDIX D: PARTIES OF RECORD, PARTICIPANTS IN FACILITATED WORKSHOPS AND HEARING WITNESSES

PARTY	PARTICIPANTS AND/OR WITNESSES
The Public Utilities Board	John Athas, Mary Neal, and Daniel Peaco of Daymark Energy Advisors; Brady Ryall, President Ryall Engineering Ltd.
Manitoba Hydro	Darren Rainkie, Vice-President, Finance & Regulatory, Manitoba Hydro;
	Greg Barnlund, Division Manager, Rates & Regulatory Affairs, Manitoba Hydro;
	David Cormie, Division Manager, Power Sales & Operations, Manitoba Hydro;
	Terry Miles, Division Manager, Power Planning, Manitoba Hydro;
	David Swatek, Manager, System Planning (Transmission), Manitoba Hydro;
	Kelly Derksen, Manager, Cost of Service, Manitoba Hydro;
	Michael O'Sheasy, Vice President, Christensen Associates Energy Consulting, LLC;
	Robert Camfield, Vice President, Christensen Associates Energy Consulting, LLC;

Consumer Coalition	William O. Harper, President, Econalysis Consulting Services;
General Service Small & General Service Medium Representative	Ian Chow, Senior Consultant, Jerome Leslie, Consultant and A.J. Goulding President, London Economics International; LLC.
Green Action Centre	Paul Chernick, President, Resource Insight, Inc.;
Manitoba Industrial Power Users Group	Patrick Bowman, Principal, InterGroup Consultants Ltd.;
Manitoba Keewatinowi Okimakanak Inc.	(No Witnesses)
Manitoba Metis Federation	(No Witnesses)
Winnipeg (City of)	John Todd, President, Elenchus Research Associates Inc.