COST ALLOCATION METHODOLOGY

1.0 PURPOSE

The purpose of this evidence is to describe OPG's cost allocation methodology.

2.0 OVERVIEW

Overall, OPG's cost allocation methodology is consistent with that which was accepted by the OEB in the OEB-approved EB-2020-0290 settlement proposal. The cost allocation methodology distributes OPG's central and common costs across its operations and to its subsidiary businesses. This includes the costs of corporate Support Services (Ex. F3-1-1) and Operations and Project Support groups (Ex. F2-2-1 and Ex. F1-2-1) as well as centrally-held costs (Ex. F4-4-1).

OPG retained Elenchus Research Associates ("Elenchus") to confirm the consistency of its cost allocation methodology as applied to OPG's 2025-2031 Business Plan ("Business Plan"), with the methodology reflected in the payment amounts set by the OEB in EB-2020-0290, including certain updates and refinements subsequently made to the methodology. The Elenchus report is provided in Attachment 1 ("Elenchus Report").

The updates and refinements made to the cost allocation methodology are discussed further below and identified in Section 3.1 of the Elenchus Report. In summary, refinements were made to reflect changes in OPG's business such as inclusion of the Darlington New Nuclear Project ("DNNP") facilities and allocation of costs during the Pickering Refurbishment outage, and to enhance the methodology by implementing greater use of specific identification and reduced reliance on management estimation. Elenchus concluded that it "finds that OPG's current cost allocation methodology, including the use of asset service fees, is consistent with the methodology reflected in the OPG payment amounts set by the OEB in EB-2020-0290 and as reviewed by Elenchus for that proceeding."[1]

[1] Elenchus Report, p. 27.

3.0 METHODS OF ALLOCATION

The cost allocation methodology uses two methods to distribute costs among the Cost Allocation Sites: direct assignment and allocation.

3.1 Direct Assignment

Direct assignment comprises specific identification or estimation of resources (or portions of resources) that are spent on a particular business or generating facility (or groups of similar generating facilities). Certain costs discussed within the Elenchus Report can be assigned to the Nuclear business as a whole, rather than specifically to one of the nuclear stations. In those instances, the primary cost driver to apportion these costs to each of the sites, as applicable, is the number of generating units at each site. Where Central and Common Costs are directly assigned to an RG Region, rather than to an individual generating facility (or groups of similar generating facilities), the primary cost driver to apportion these costs between regulated and unregulated sites within a Region is direct base OM&A costs of such sites. Management estimation of resources used by the business may be based on current time estimates or historical activity.

3.2 Allocation

Allocations are used for costs that are not directly assigned to a business or generating facility (or groups of similar generating facilities). In these cases, a cost driver is used to allocate the costs of the resource. A cost driver is a formula for sharing the cost of a resource among those who caused the cost to be incurred. The primary allocator uses a blend of planned OM&A costs and capital expenditures (“OM&A/Capital”). For certain organizations such as Human Resources and the IT group, OPG predominantly uses total labour costs and the number of IT end users, respectively, as a cost driver to allocate the departments costs.

OPG maintains slight variations of allocation rules for certain instances. For example, specific Corporate or Operations support organizations perform oversight type functions for OPG’s wholly-owned subsidiaries, in this case, allocation rules include the subsidiaries in the methodology. This treatment is consistent with the cost allocation methodology from EB-2020-0290.

3.3 Application of Methodology

OPG continues to use three steps when allocating a department's costs:

- Step One – Specific Identification of Resources

The costs of labour and non-labour resources specifically identified to a Cost Allocation Site are assigned to it.

- Step Two – Estimation of Resources

The next step is to identify the resources in each department that directly support more than one facility and to estimate the resources attributable to each of these facilities (or group of similar facilities). The resources are directly assigned by proportion based primarily on the estimated time required by the respective department.

- Step Three – Assign Cost Drivers

OPG uses the appropriate standardized cost drivers for all remaining activities or expenses.

Appendix A within the Elenchus Report reflects the allocation methodology of Central and Common costs during the Business Plan period. Appendix B provides the distribution details of the directly assigned costs in Appendix A to the Nuclear business, including the DNNP facilities.

4.0 AFFILIATE RELATIONSHIPS

The cost allocation methodology attributes applicable Central and Common Costs to the company's operations carried out through OPG's wholly-owned subsidiaries which include Atura Power, Laurentis Energy Partners ("Laurentis"), PowerON Energy Solutions ("PowerON"), Origin Nuclear Incorporated ("Origin"), as well as energy trading and other unregulated non-generation activities. Atura Power operates a fleet of unregulated combined cycle gas-fired generating stations and other facilities in Ontario. Laurentis operates an unregulated engineering, technical services and isotopes business. PowerON is a transportation electrification and charging infrastructure services provider. Origin offers various services and expertise to nuclear operators.

As of the date of this report, an agreement has been signed for the sale of OPG's wholly owned subsidiary, Eagle Creek Renewable Energy ("Eagle Creek"), and is expected to close in 2026 and therefore the cost allocation methodology assessment within the Elenchus Report excludes Eagle Creek.

The cost allocation methodology attributes applicable Central and Common costs to the subsidiaries as discussed in Section 3.2.2 of the Elenchus Report. This is accomplished in two ways:

- General allocation of OPG's corporate oversight and ownership costs as the parent entity; and
- Charges for Central and Common costs applicable to specific resources that may be transacted by subsidiaries from time to time, on a cost basis plus a standard overhead allocation rate, with the parent.

Elenchus also considered the methodology used by OPG to derive the Asset Service Fees ("ASF") charged for the use of certain central and joint-use assets to both the regulated and unregulated businesses. Elenchus concluded that the methodology used is consistent with prior applications, remains reasonable given the operation of OPG's business and is consistent with cost causality principles. Specifically, as it relates to affiliate relationships, Elenchus review included the ASFs used to:

- attribute the costs to Laurentis for use of the Darlington nuclear assets in relation to producing medical isotopes, and
- attribute costs related to IT Assets that will be exclusively or near exclusively used by the DNNP facilities to the DNNP LP.

LIST OF ATTACHMENTS

Attachment 1: Cost Allocation Review Ontario Power Generation by Elenchus Research Associates

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elenchus.ca

Cost Allocation Review

Ontario Power Generation

Report prepared by
Elenchus Research Associates Inc.

10 December 2025

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1 INTRODUCTION AND BACKGROUND

Ontario Power Generation Inc. ("OPG") retained Elenchus Research Associates ("Elenchus") to assess the consistency of its cost allocation methodology for shared operations, maintenance and administration ("OM&A") costs and capital assets with that reflected in the OPG payment amounts set by the Ontario Energy Board ("OEB") in EB-2020-0290 including certain updates and refinements subsequently made to the methodology. Elenchus conducted its review of the cost allocation methodology in the context of OPG's 2025-2031 Business Plan ("Business Plan"). Elenchus understands that the Business Plan will underpin OPG's upcoming 2027-2031 rate application to the OEB. As a result, our review focused on the 2027-2031 period. Elenchus previously conducted a similar review of OPG's cost allocation methodology as part of the EB-2020-0290 proceeding.

1.1 TREATMENT OF CORPORATE SUPPORT, OPERATIONS SUPPORT AND CENTRAL AND COMMON COSTS

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG utilizes a cost allocation methodology to allocate the company's centre-led support and administrative services ("Corporate Support"), enterprise operations and project support ("Operations Support") and other common OM&A costs (together, "Central and Common Costs") across its operations. This methodology also applies to the allocation of OPG's Central and Common Costs to the new small modular reactors ("SMRs") being developed as part of OPG's Darlington New Nuclear Project ("DNNP"), which Elenchus understands is intended to be constructed, operated and maintained by a separate partnership being formed for that purpose. Elenchus also understands that OPG will be contracted as the project manager and operator of these facilities, once they are transferred to a separate partnership.

The cost allocation methodology allocates Central and Common Costs to the core electricity generating businesses and wholly owned subsidiaries. The core electricity

generating businesses are Nuclear and Renewable Generation[1]. The DNNP facilities (including as part of a separate partnership) are considered a part of the Nuclear business for cost allocation purposes. As applicable, Central and Common Costs are allocated within Nuclear and Renewable Generation, among specific generating facilities or groups of similar generating facilities ("Cost Allocation Sites"). The cost allocation methodology also allocates applicable Central and Common Costs to the company's operations carried out through wholly-owned subsidiaries, including Atura Power, Laurentis Energy Partners ("Laurentis"), PowerOn Energy Solutions ("PowerON") and Origin Nuclear Incorporated ("Origin"), as well as energy trading and other unregulated non-generation activities.[2,3]

Where applicable, OPG's businesses, including the DNNP facilities, are also charged cost-based Asset Service Fees ("ASFs") for the use of certain corporate-level or joint-use assets owned and operated by the company.[4] Where applicable, the ASFs are in turn distributed amongst specific Cost Allocation Sites.

OPG's Nuclear business comprises the company's Darlington and Pickering nuclear generating stations located in Ontario, which are regulated by the OEB. The DNNP facilities, currently under construction and held by OPG, are also regulated by the OEB. OPG informed Elenchus that, once transferred to a separate partnership, DNNP would be expected to become a regulated asset of that partnership. Therefore, while our previous review of OPG's cost allocation methodology did not specifically focus on the division of costs amongst the Cost Allocation Sites within what was then OPG's fully owned, fully regulated Nuclear business, with the DNNP partnership expected to become a separate OEB regulated entity, this review specifically examined these aspects of the cost allocation methodology.

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1 Known as Renewable Generation & Power Marketing at the time of our review in EB-2020-0290.

2 Use of terms "regulated" and "unregulated" in this report refers to regulation by the OEB as it relates to payment amounts received for electricity generation from the generating facilities.

3 In October 2025, OPG entered into an agreement for the sale of OPG's US-based subsidiary, Eagle Creek Renewable Energy ("Eagle Creek"), which OPG expects to close in 2026. As such, the assessment of OPG's cost allocation methodology excludes Eagle Creek.

4 A portion of the costs charged through ASFs as it relates to OPG's Real Estate common assets are included in Corporate Support costs, denoted with "Asset Service Fees" as the distribution method in Appendix A.

At the time of our last review in EB-2020-0290, OPG was planning for the shutdown of all six operating units at the Pickering nuclear generating station. Since then, OPG shut down two such generating units; however, a decision has been made to proceed with the refurbishment of the remaining four operating units ("Pickering Refurbishment"). Elenchus understands that the refurbishment is expected to commence execution beginning in 2027, with all four units being offline for most of the 2027-2031 period as a result.

OPG's Renewable Generation business is organized in three regional operations groups ("RG Regions") and comprises 54 regulated hydroelectric generating stations and 15 unregulated hydroelectric, thermal and solar generating facilities, all of which are located in Ontario. Our review included the aspects of the cost allocation methodology that distributed costs as between the regulated and unregulated facilities operating within the respective RG Regions.

Atura Power operates a fleet of unregulated combined cycle gas-fired generating stations and other facilities in Ontario. Laurentis operates an unregulated engineering, technical services and isotopes business. PowerON is a transportation electrification and charging infrastructure services provider. Origin offers various services and expertise to nuclear operators.

OPG informed Elenchus that there have been organizational changes at OPG since our last review in EB-2020-0290. These changes are reflected in the Business Plan, and in the OPG functional structure used to present the cost allocation results in this report. The organizational changes are discussed in greater detail in section 3.3 of this report.

A summary of Cost Allocation Sites to which Central and Common Costs are allocated based on the Business Plan can be found in Table 1 below.

Table 1: Summary of Cost Allocation Sites

Business	Regulated / Unregulated	Cost Allocation Site
Nuclear Generation	Regulated	Pickering
		Darlington
		DNNP
Renewable Generation[5]	Regulated & Unregulated	Eastern Region
		Western Region
		Niagara Region
Other Business	Unregulated	Atura Power
		Laurentis Energy Partners
		PowerON Energy Solutions
		Origin Nuclear
		Energy Trading
		Other

OPG's Corporate Support costs and Operations Support costs are categorized based on the structure of the company.[6] A summary of Corporate Support costs based on the Business Plan can be found in Table 2 below. A summary of the Operations Support costs based on the Business Plan can be found in Table 3 below. OPG also allocates common costs incurred at the level of each RG Region ("RG Regional Common Costs") between regulated and unregulated Cost Allocation Sites, as discussed in Section 4.

[5] The addition of the Niagara Region as part of the organizational reporting structure within the Renewable Generation business since EB-2020-0290 does not impact the Company's cost allocation methodology as (1) the costs are not allocated on the basis of the number of such Regions and (2) consistent Cost Allocation Sites continue to be maintained for individual generating facilities (or group of similar generating facilities) within Renewable Generation. For example, the Niagara region regulated hydroelectric facilities (Sir Adam Beck generating complex and DeCew Falls generating stations) have remained a constant cost allocation site.

[6] The categories are presented in the manner OPG has identified them for the upcoming 2027-2031 rate application.

Table 2: Summary of Corporate Support Service Provider Organizations ($M)[7]

Group/Category	Primary Departments or Services	2027-31 Business Plan (Avg per year)	% of Total
Chief Information Office	Cyber Security, Enterprise Services, Application Development, Customer Experience, IT Projects, Telecom/Hardware/Software, Data Services, Shared Services	$245.0	42%
Supply Chain	Project Support, Quality Assurance, Category Management, Strategic Programs, Purchasing, Plant Operations	$53.8	9%
Real Estate[8]	Real Estate Services, Nuclear Facility Services, Projects & Accommodations, Employee Experience, Leases & Utilities	$102.6	18%
Finance	Assurance, Controllership and Financial Projects, Business Planning & Reporting, External Reporting and Accounting Policy, Fund Management, Treasury, Commercial Integration and Strategy & New Growth, Income Tax	$71.1	12%
Human Resources	Compensation & Benefits, Recruitment & Onboarding, Labour Relations, Talent Management & Leadership Development, Workforce Planning, HR Business Partnering, Ethics & Equity, Health Services	$39.5	7%
Corporate Centre	Commercial Management, Corporate Affairs & Hydro Business Development, Regulatory Affairs, Law, Governance & ESG, Corporate Business Development & Strategy, Executive Operations	$72.8	12%
Total		**$584.8**	**100%**

7 Shown excluding costs charged through ASFs.

8 Inclusive of lease and utilities costs incurred on behalf of the enterprise.

Table 3: Summary of Operations Support Service Provider Organizations ($M)

Group/Category	Primary Departments or Services	2027-31 Business Plan (Avg. per year)	% of Total
Environment, Health & Safety	Environment, Health & Safety	$23.4	4%
Enterprise Engineering	Advanced Inspection and Maintenance, Central Engineering, Design & Project Engineering, Station Engineering, Chief Enterprise Engineer	$234.5	40%
Enterprise Projects	Nuclear Projects, RG Major Projects, Enterprise Project Management Office	$12.0	2%
Integrated Fleet Management	Fleet Performance (including Stakeholder Relations), Enterprise Learning, Security & Emergency Services, VP Integrated Fleet Management	$199.3	34%
Other Operations Support	Nuclear Oversight, Nuclear Regulatory Affairs, Nuclear Sustainability Services and Strategy, Dam Safety & Water Resources, Energy Markets, Commercial Services, Chief Nuclear Officer, Chief Operations Officer, Chief Projects Officer, SVP Renewable Generation & RG Programs and Strategy	$115.1	20%
Total		**$584.3**	**100%**

Central and Common Costs also include centrally-held costs, which are enterprise-wide costs that are recorded centrally by OPG for reasons such as record-keeping efficiency and oversight. A summary of the centrally-held costs based on the Business Plan can be found in Table 4 below.

Table 4: Summary of Centrally Held Costs ($M)

Group/Category	Primary Departments or Services	2027-31 Business Plan (Avg per year)	% of Total
Pension / OPEB Centrally Held	Pension / OPEB Centrally Held[9]	$(216.5)	-312%
Insurance	OPG-Wide Insurance, Nuclear Insurance	$75.2	109%
Employee Performance Incentives	Employee Performance Incentives	$51.6	74%
Other	Fiscal Calendar Adjustment, Vacation Accrual/Banked Time, Other	$20.4	29%
Total		**$(69.3)**	**100%**

1.2 OPG Cost Allocation Methodology Overview

OPG's cost allocation methodology allocates Central and Common Costs using direct assignment where reasonably possible. Direct assignment comprises specific identification or estimation of resources (or portions of resources) that are spent on a particular business or generating facility (or a group of similar generating facilities). In cases where specific identification or estimation is not reasonably possible, costs are allocated to businesses and generating facilities (or groups of similar generating facilities) using cost drivers based on cost causation, which are formulaic in nature.

Asset service fees are determined using principles of cost causation and primarily apply to corporate information technology ("IT") and real estate assets, certain joint-use assets within RG operations, and, going forward, certain assets that would be held by OPG for the exclusive or near-exclusive use of the DNNP partnership. OPG also applies ASFs for the use of its regulated nuclear assets by the unregulated operations for the purpose of

[9] The Pension / OPEB Centrally Held amount reflects the difference between pension and other post-employment benefit ("OPEB") costs distributed directly to departments (and in turn allocated to Cost Allocation Sites, as applicable) through standard labour rates, and the total costs based on actuarial estimates. A negative centrally held balance allocated using the cost allocation methodology offsets a portion of the costs distributed to departments and associated Cost Allocation Sites through standard labour rates.

producing medical isotopes in the Darlington reactors. Asset service fees are discussed further in section 3.3 of this report.

OPG's allocation methodology for Central and Common Costs was previously reviewed by an independent expert in each of 2006, 2010 and 2013, and most recently by Elenchus in 2020, as part of the company's respective payment amounts applications to the OEB. These reports were filed by OPG in EB-2007-0905, EB-2010-0008, EB-2013-0321 and EB-2020-0290, respectively, and concluded that the cost allocation methodology used by the company was appropriate and, in the 2013 and 2020 reviews, that its ASF approach is reasonable. The OEB accepted OPG's cost allocation methodology (including ASFs) in setting payments amounts in EB-2007-0905, EB-2010-0008, EB-2013-0321 and EB-2016-0152. In the most recent payment amounts proceeding, EB-2020-0290, parties to a settlement approved by the OEB accepted OPG's cost allocation methodology (including ASFs).

2 Elenchus Approach to Cost Allocation Methodology Review

2.1 Review of Existing Methodology

Elenchus undertook the following actions as part of its review of OPG's cost allocation methodology:

- Reviewed publicly available information and received briefings from OPG staff to understand OPG's business and organization, including the anticipated DNNP partnership entity and any other changes of note since EB-2020-0290;
- Reviewed prior evidence filed with the OEB on OPG's cost allocation methodology and past OEB decisions and settlements in OPG's payment amounts proceedings as they relate to cost allocation methodology (including ASFs);
- Conducted meetings with OPG staff in order to validate that the cost allocation methodology currently used is consistent with the methodology reviewed by

Elenchus in 2020/2021 and accepted by the OEB in EB-2020-0290 and to identify any changes made to the methodology since that time;

- Received and reviewed briefings from OPG staff responsible for business planning and cost allocation oversight related to the cost allocation methodology (including ASFs) and the Business Plan, including any changes made to the methodology since EB-2020-0290;
- Reviewed prior documentation from our previous review of OPG's cost allocation methodology;
- Reviewed OPG's cost allocation model based on the Business Plan;
- Evaluated changes to the cost allocation methodology made since EB-2020-0290 identified through the above work, including the new ASFs, the integration of new subsidiaries and the allocation of costs to the DNNP; and
- Prepared this report documenting the work undertaken by Elenchus and Elenchus' findings.

2.2 ELENCHUS WORK

This section provides more details on the work undertaken by Elenchus.

2.2.1 REVIEW OF PRIOR OEB EVIDENCE

Elenchus reviewed the following evidence filed in prior OEB proceedings to confirm its understanding of the cost allocation methodology accepted by the OEB:

- *Review of Cost Allocation Methodology for Centralized Services and Common Costs*, HSG Group Inc., August 23, 2013, EB-2013-0321, Exhibit F5, Tab 5, Schedule 1.
- Base OM&A - Regulated Hydroelectric, September 27, 2013, EB-2013-0321, Exhibit F1, Tab 2, Schedule 1.
- Allocation of Support Services Costs, December 31, 2020, EB-2020-0290, Exhibit F3, Tab 1, Schedule 1.

- Cost Allocation Methodology, December 31, 2020, EB-2020-0290, Exhibit F3, Tab 1, Schedule 4.
- *Cost Allocation Review Ontario Power Generation*, Elenchus Research Associates Inc., December 30, 2020, Exhibit F3, Tab 1, Schedule 4, Attachment 1, and as amended April 22, 2021.
- Asset Service Fees, December 31, 2020, EB-2020-0290, Exhibit F3, Tab 2, Schedule 1.
- Various OEB Staff Interrogatories from EB-2020-0290 pertaining to OPG's cost allocation methodology, including asset service fees.

2.2.2 Elenchus Meetings with OPG Staff

Elenchus held several meetings with OPG staff in order to confirm whether the cost allocation methodology for Central and Common Costs (including ASFs) used by OPG is consistent with the OEB approved cost allocation methodology and to review the changes made since EB-2020-0290 (when Elenchus last reviewed OPG's cost allocation methodology).

Some of the questions raised at these meetings were:

- What is the organizational structure of OPG as set out in the Business Plan compared to at the time of EB-2020-0290?
- What are the common corporate and business level functions, services and costs of OPG compared to EB-2020-0290?
- What OPG assets are subject to regulation compared to EB-2020-0290?
- What are OPG's unregulated assets and businesses compared to EB-2020-0290?
- What changes has OPG introduced to the cost allocation methodology since EB-2020-0290 that accommodate the changes in OPG's regulated and unregulated businesses and/or as set out in the Business Plan? What is the rationale for those changes?

- What changes has OPG introduced to the cost allocation methodology since EB-2020-0290 in response to the changes in the common corporate and business level functions, services and costs as set out in the Business Plan? What is the rationale for those changes?
- What other changes has OPG introduced to the cost allocation methodology since EB-2020-0290? What is the rationale for those changes?
- Are there changes to how the cost allocation methodology is applied and administered? What are the Cost Allocation Sites compared to at the time of EB-2020-0290?
- What are the results of the cost allocation methodology applied to the Business Plan?
- What is the expected nature of the arrangements between OPG and DNNP LP with respect to the DNNP?
- How does the nature of SMRs compare to OPG's existing nuclear facilities and does this affect the cost allocation methodology?
- Will the Pickering Refurbishment have an impact on the cost allocation methodology?
- What is the nature of the arrangements for the production of isotopes at OPG's Darlington reactors?

3 ELENCHUS FINDINGS

Based on our review of prior evidence filed with the OEB on OPG's cost allocation methodology, review of prior documentation from our previous review of OPG's cost allocation methodology, review of the cost allocation model and the various meetings conducted with OPG staff, Elenchus has made the findings outlined below.

The findings are organized in five sections. Section 3.1 addresses changes to the cost allocation methodology made by OPG since our previous review in EB-2020-0290. Section 3.2 discusses the new Cost Allocations Sites introduced into the methodology

since that time, including the DNNP facilities, while Section 3.3 discusses the implications of the organizational changes made by OPG since EB-2020-0290. Section 3.4 discusses the implications of the Pickering Refurbishment on the cost allocation methodology. Section 3.5 outlines Elenchus findings with respect to the asset service fees.

3.1 CHANGES TO COST ALLOCATION METHODOLOGY

OPG has implemented minor updates and refinements to the cost allocation methodology since the methodology Elenchus reviewed in EB-2020-0290. The main changes to the methodology are reviewed in the following sections. The integration of the DNNP facilities into the cost allocation model is consistent with OPG's cost allocation methodology.

Having considered the updates and refinements noted in this section, Elenchus finds that there have been no material changes to the overall design of OPG's cost allocation methodology since EB-2020-0290 and OPG's cost allocation methodology continues to be consistent with the principles and approaches reviewed in prior OEB proceedings and regulatory best practices. This includes the allocation of costs to the DNNP facilities.

In particular, the methodology continues to reflect the nature of OPG's business including provision of centre-led services and common operating costs, where reasonably possible directly assigning the costs to OPG businesses or facilities. For shared costs that cannot be assigned directly, cost drivers continue to be based on causal relationships and applied in a standardized manner, taking into account the practicality of obtaining and maintaining the necessary data and the stability of the data over time. Cost allocations continue to be applied at the level of detail corresponding to major cost categories within the company's accounting records, follow an internal stakeholdering and review process as part of the corporate business planning cycle, and are maintained and administered by dedicated resources through a centralized cost allocation model and tools.

Direct assignment of Central and Common Costs continues to comprise specific identification of costs to a particular business or generating facility (or a group of similar generating facilities) as well as management estimation of resources (or portions of resources). Management estimation continues to be informed by a periodic departmental review and challenge process.

Where costs are not directly assigned to a business or generating facility (or a group of similar generating facilities), the primary cost driver used under OPG's cost allocation methodology continues to be the blend of planned OM&A costs and capital expenditures ("OM&A/Capital"), other than for human resources and IT related costs. Human resources related costs (where not directly assigned) are generally allocated using a labour resource-based cost driver and IT related costs (where not directly assigned) are generally allocated using an IT end user cost driver.

Where Central and Common Costs are directly assigned to the Nuclear business as a whole, rather than to a specific nuclear generating station, the primary cost driver to apportion these costs to each of the sites, as applicable, is the number of generating units at each site ("Generating Units").

Where Central and Common Costs are directly assigned to an RG Region, rather than to an individual generating facility (or a group of similar generating facilities), the primary cost driver to apportion these costs between regulated and unregulated sites is direct base OM&A costs of such sites. RG Regional Common Costs that are not directly assigned to individual generating facilities (or groups of similar generating facilities) continue to be allocated between regulated and unregulated sites using station capacities (i.e., Maximum Continuous Rating or MCR[10]) for the applicable facilities.

The cost drivers are applied in a consistent manner.

In Elenchus' experience, periodically reviewing cost distribution methods is an important element of a mature cost allocation process. The changes made by OPG as described below are in line with these continuous improvement practices.

3.1.1 Greater Use of Specific Identification in Supply Chain

In our previous review of OPG's cost allocation methodology, Elenchus observed that OPG was able to increase the use of direct assignment via specific identification, over management estimation, for the distribution of Corporate Support costs. Greater use of

[10] MCR is the maximum electrical power output that can be continuously generated, provided adequate inflow is available. The unit is assumed to be operating at unity power factor and at the indicated reference gross head. MCR observes generator and turbine limitations.

direct assignment via specific identification yields more precise and objective cost allocation results.

In this review, Elenchus noted that OPG was able to further increase the use of specific identification with respect to Corporate Support Costs, within the Supply Chain function. This reflects increased granularity in the manner in which OPG is tracking these shared costs in the underlying cost accounting records. For example, fleet purchasing and warehouse logistics personnel assigned to servicing particular facilities (or group of facilities) are now tracked in dedicated cost centers. Elenchus finds this to be an improvement in the cost allocation methodology.

As shown in Table 6, taking into account the above change, approximately 27% of Corporate Support Costs planned over the 2027-2031 period are distributed using specific identification, compared to 21% at the time of Elenchus' previous review.

3.1.2 Reduced Reliance on Management Estimation

While OPG's methodology continues to be effective at directly assigning shared costs where reasonably possible, Elenchus observes that the effectiveness of management estimation as a means of direct assignment is inherently dependent on the extent of judgement involved. As part of its ongoing due diligence over the cost allocation methodology, since EB-2020-0290, OPG has updated the allocation methods for certain enterprise-wide functions by reducing the use of management estimation and increasing the use of cost drivers. Elenchus has reviewed these changes and agrees that, given the degree of judgement required for these areas, decreasing the reliance on management estimation is reasonable and better reflects the nature of the underlying activities. Three examples of the changes are provided below.

As the first example, OPG has replaced management estimation with the use of the OM&A/Capital allocator for the distribution of costs of the Stakeholder Relations and Indigenous Relations departments within Corporate Affairs and Hydro Business Development. Elenchus finds it reasonable that the primarily enterprise-level nature of the work conducted by these teams is better suited for allocation using a cost driver.

As the second example, OPG has significantly reduced reliance on management estimation and increased the portion of the support costs being distributed using the OM&A/Capital allocator for the Enterprise Project Management Office, which provides centralized project management support in areas such as project controls and scheduling. Elenchus finds it reasonable that allocating these costs using a cost driver better aligns to the company-wide range of projects supported by this team.

As the third example, OPG has replaced management estimation with the use of a cost driver to allocate costs of the Energy Markets department within each of the Nuclear business and the Renewable Generation business. Energy Markets coordinates the offering of OPG's electricity generation into the electricity market and carries out associated strategic support activities. OPG is now using the Generating Units allocator to distribute the costs amongst Nuclear sites and the OM&A/Capital allocator amongst Renewable Generation sites. Elenchus finds it is reasonable that a centralized function such as Energy Markets is more suited to allocation using a cost driver. Elenchus further recommends that, given the electricity market-facing nature of the work, OPG consider using a MCR cost driver rather than OM&A/Capital for allocating costs within Renewable Generation. OPG has estimated that such a change would reduce the amounts attributed to the regulated hydroelectric facilities by less than $1M annually over the 2027-2031 period, which is not material to the overall cost allocation results.

3.2 NEW COST ALLOCATION SITES

OPG has updated its Cost Allocation Sites in line with changes to its business since EB-2020-0290, for both regulated and unregulated operations, as discussed below. The new Cost Allocation Sites have been integrated into the cost allocation model used for the 2027-2031 period. This has not changed OPG's cost allocation methodology.

3.2.1 DARLINGTON NEW NUCLEAR PROJECT

The DNNP is a greenfield nuclear project to construct up to four SMRs at OPG's DNNP site. Following several years of planning and preparation, OPG began the construction of the first SMR earlier in 2025. Construction of the remaining planned SMRs is subject to

further approvals. OPG has informed Elenchus that it expects that the DNNP will be transferred to a newly formed partnership entity with third parties, for the purpose of continuing to construct and ultimately operate the SMRs. OPG also informed Elenchus that the partnership entity is not expected to have its own workforce and that, under a series of agreements, OPG would act as the project manager and operator of the DNNP facilities and administer the partnership.

The DNNP facilities represent a new Cost Allocation Site within OPG's Nuclear business and receive an allocation of Central and Common Cost using the same methodology as the Pickering and Darlington nuclear stations, including, as applicable, during the DNNP's construction period. Elenchus agrees with this treatment. Given that the DNNP facilities will continue to be substantively integrated with OPG's business after they are transferred to the new entity, Elenchus finds it appropriate that OPG will continue with the established cost allocation methodology after the transfer.

Where Central and Common Costs applicable to DNNP facilities are directly assigned to the Nuclear business but require further allocation to individual stations, OPG's methodology uses the Generating Units cost driver that includes the DNNP facilities to further allocate these costs. As the SMR units are designed to be smaller in footprint, simpler in operation and more staff-efficient than the CANDU reactors at the Pickering and Darlington stations, OPG has adjusted this cost driver to treat the four SMR units as equivalent to one CANDU unit. Elenchus understands that the first SMR unit will require most of the support resources needed for the entire four-unit station and subsequent units will require fewer incremental resources due to the fleet economies of scale. As such, OPG is treating the first SMR as equivalent to the four SMRs as part of the Generating Units cost driver. Elenchus has reviewed the rationale for these internal management assessments and believes this treatment is reasonable.

Specific to the construction period, OPG's cost allocation methodology primarily allocates Corporate Support costs to the DNNP facilities. Such costs are predominately distributed to the DNNP facilities on the basis of cost drivers. For example, the Corporate & Technology Services group allocates costs related to internal IT services and functions to the DNNP facilities using the estimated number of IT-end users associated with the

project. As OPG does not otherwise charge such indirect costs to capital projects including the DNNP, Elenchus finds this cost allocation treatment to be a reasonable manner for recognizing that the DNNP construction drives a level of organizational effort across corporate departments.

3.2.2 Unregulated Affiliates

The cost allocation methodology continues to incorporate unregulated businesses to ensure they receive an allocation of shared costs. Following OPG's agreement to sell its Eagle Creek business, this now includes four unregulated operating subsidiaries, being Atura Power, Laurentis, PowerON and Origin, with the latter two representing additions since EB-2020-0290. As in our previous review, while each of these wholly-owned entities separately maintain or specifically source its workforce and most support and administrative resources, OPG allocates the cost of certain corporate-level resources to these operations in recognition of its oversight and ownership role for these businesses. All of these subsidiaries are treated in a consistent manner under the cost allocation methodology.

Elenchus continues to find that the allocation of OPG's oversight and ownership costs to the subsidiaries follows existing cost drivers for the applicable Central and Common Costs and is consistent with how these costs are allocated to OPG's other businesses. For example, Corporate Governance & Corporate Secretary & ESG department costs are allocated to the oversight of the unregulated businesses using the OM&A/Capital allocator in the same manner that they are allocated to the Nuclear and Renewable Generation businesses. Elenchus also agrees with OPG's approach to determining which departments within Central and Common Costs should be allocated to the unregulated subsidiaries, which is based on the nature of the departments' work. For example, the costs of certain Finance teams responsible for the consolidation of subsidiaries' business planning and financial results, OPG executives serving on subsidiaries' boards of directors, and the enterprise-wide internal audit function are attributed to the unregulated subsidiaries. On the other hand, OPG does not allocate the costs of the Shared Services department, which is responsible for financial transactional services, the human

resources service centre and the payroll function, as the subsidiaries do not receive such services from OPG.

Unregulated subsidiaries may purchase specific services or resources from OPG on a cost basis. In those circumstances, Elenchus confirmed that a commensurate portion of Central and Common Costs, corresponding to an estimate of such costs for any transferred labour resources, is charged or otherwise attributed to the unregulated subsidiaries. For administrative efficiency of the cost allocation process, OPG continues to use a standard overhead allocation rate to charge such costs, set at approximately 25% over the upcoming rate application period.[11]

Overall, Elenchus concludes that, between the use of corporate oversight allocations and an overhead allocation rate for transferred labour resources, OPG reflects the impact of the unregulated subsidiaries in the cost allocation methodology in a manner that appropriately separates costs between regulated and unregulated businesses.

3.3 ORGANIZATIONAL CHANGES

A key principle for sound cost allocations is that costs should be allocated and cost drivers selected based on cost causality for underlying activities, not the organizational structure. Since Elenchus' last review in EB-2020-0290, there have been organizational changes at OPG. Elenchus reviewed these changes and noted that most represented changes in reporting relationships rather than changes in functional accountabilities. Therefore, these changes appropriately did not involve modifications to the cost allocation methods. Elenchus also reviewed the allocation methods used for each of the new departments that have been formed and agrees they are reasonable. Appendix C highlights the main organizational changes made since our last review of OPG's cost allocation methodology in EB-2020-0290.

[11] The costs of management performance incentives, as applicable, are charged in addition to the standard overhead allocation rule.

3.4 PICKERING REFURBISHMENT

OPG is planning for the refurbishment of Units 5 to 8 at the Pickering nuclear generating station and expects project execution to commence in 2027, after the four units have been taken offline in late 2026. The cost allocation methodology remains consistent in view of this large project.

Elenchus finds the methodology is suitable to reflect the project's impacts on OPG's costs within the allocation of Central and Common Costs. For example, capital project expenditures will increase the share of costs allocated to the Pickering station when using the OM&A/Capital allocator, which is indicative of a reasonable causal relationship between the level of organizational effort and the scale of the project. Elenchus also observes that the cost allocation methodology is applied in the same manner to OPG's other large projects such as the ongoing Darlington Refurbishment Project and the DNNP.

Additionally, Elenchus understands that, although it will not be producing electricity for several years due to the ongoing refurbishment, the Pickering station will remain an active nuclear site, requiring ongoing maintenance, care and compliance outside of refurbishment activities. Elenchus finds that OPG's cost allocation methodology is suitable to these circumstances as it does not rely on methods or cost drivers that are tied to electricity production. For example, the Generating Units allocator, used to allocate directly assigned Nuclear business Central and Common Costs among the Nuclear sites, does not vary with the level of production.

Elenchus specifically considered whether the application of the Generating Units allocator, which is static in nature, to the applicable departments as set out in Appendix B supports the allocation of such costs to the Pickering station during the refurbishment outage. Based on its review, Elenchus believes that it is reasonable that these departments continue to allocate costs to the Pickering station using the Generating Units allocator during the refurbishment outage, in the manner reflected in the Business Plan. For example, continuing to allocate the Security & Emergency Services department costs to the Pickering station in this manner recognizes that the level of effort to secure the site is not correlated to whether the station is producing electricity or is temporarily offline for a refurbishment, which aligns to the principle of cost causality.

Elenchus further observes that continued allocation of applicable costs to the Pickering station during the refurbishment period maintains stability in the overall allocation of costs. In particular, it avoids potentially significant volatility in cost allocation results that are likely should the Pickering station be temporarily excluded from the allocation base, causing temporary increases in the costs attributed to the Darlington station, Renewable Generation facilities and other parts of the business, only to return to the more typical levels as Pickering units begin to return to service.

Additionally, Elenchus confirmed that the Generating Units allocator excludes the two Pickering units that were permanently shut down in 2024.

3.5 Asset Service Fees

As noted earlier, OPG continues to utilize cost-based ASFs to charge its businesses for the use of certain corporate-level or joint-use assets owned and operated by the company, including corporate IT assets and Renewable Generation assets (e.g., service centers and certain control dams used by both regulated and unregulated generating facilities). Asset service fees continue to be determined using the principles of cost causation and are included as operating costs of the regulated businesses for the purposes of setting regulated payment amounts. Asset service fees continue to be applied in instances where no single OPG business receives greater than 90% beneficial use for a particular asset, with assets providing greater than 90% beneficial use to a single business considered to be wholly part of that business and, as applicable, included in their rate base.

With the expected DNNP partnership, OPG is also planning for ASFs to be charged to the DNNP facilities for the assets that will be held by OPG for the exclusive or near-exclusive beneficial use of the DNNP facilities. For example, Elenchus understands that certain IT assets will be developed by OPG specifically for the SMR operations.

Through this review, Elenchus confirmed that the methodology used by OPG to determine and apply the ASFs remains unchanged from our last review in EB-2020-0290. Namely, the calculation of all ASFs continues to be based on the depreciation expense, cost of capital and, where applicable, operating costs for the underlying assets, with each of

these components apportioned to the businesses using cost drivers consistent with the cost allocation methodology. For example, the ASFs for enterprise-wide IT assets are apportioned across businesses using the IT end user cost driver and the ASF for the Company's Corporate Headquarters is apportioned across the businesses using the OM&A/Capital allocator. Asset service fees for joint-use Renewable Generation assets are apportioned between the regulated and unregulated facilities using the direct base OM&A costs of such facilities.

In Elenchus' opinion, OPG's ASF approach described above remains reasonable given the operation of OPG's business and is consistent with cost causality principles. Elenchus also finds that OPG's treatment of the ASF associated directly with the DNNP facilities is reasonable, consistent with the overall ASF methodology and ensures proper attribution of the underlying costs to the respective Cost Allocation Site.

Additionally, the methodology and calculation of the ASF for the use of the Darlington generating station's reactors by an unregulated business to produce isotopes remains consistent with our review of the same for the EB-2020-0290 proceeding. Such ASFs continue to be calculated using the same components as set out above and apportioned between the Nuclear business and an unregulated business using the relative undepreciated book value of investments into the respective Darlington generation assets and the isotope-producing reactor modifications. It remains Elenchus' opinion that the isotope ASF methodology continues to reasonably align with sound cost allocation principles for the reasons set out in our previous review.

A summary of the asset service fees based on the Business Plan can be found in Table 5 below.

Table 5: Summary of Asset Service Fees ($M)

Asset Service Fees	2027-2031 Business Plan (Avg. per year)	% of Total	Cost Allocation Site
Corporate Information Technology Assets	$119.5	69%	Enterprise Wide
Corporate Headquarters	$31.1	18%	Enterprise Wide
Joint-use Renewable Generation Assets	$29.6	17%	Renewable Generation Sites
DNNP Information Technology Assets	$25.0	14%	DNNP Facilities
Nuclear Isotope Asset Usage Fee	$(31.1)	(18%)	Darlington Generating Station
Total	**$174.1**	**100%**	

4 COST ALLOCATION RESULTS

A full summary of OPG's methodology for allocating Central and Common Costs can be found in Appendix A, based on the Business Plan. Where Appendix A shows that a cost is directly assigned, it may be directly assigned to the Nuclear business as a whole, an RG Region, or to an individual generating facility (or a group of similar generating facilities). Appendix B provides the further distribution details of the directly assigned costs in Appendix A concerning each of the three sites within the Nuclear business, being the Pickering station, the Darlington station and the DNNP facilities.

Table 6 below provides a higher-level summary of the cost allocations for Central and Common Costs detailed in Appendix A, by the method of allocation, as applied to the Business Plan.

Table 6: Summary of Central and Common Cost Allocation[12,13]

Cost Distribution Method	Corporate Support Services		Centrally Held Costs		Operations Support Costs[14]
	EB-2020-0290[15]	2027-2031	EB-2020-0290	2027-2031	2027-2031
Direct Assignment - Specific	21%	27%	93%	-1%	68%
Direct Assignment - Management Estimate	22%	4%	-	-	11%
Direct Assignment - Pension/OPEB Centrally Held	-	-	-6%	124%	-
Allocated - Pension/OPEB Centrally Held	-	-	-1%	26%	-
Allocated - Physical Cost Drivers	29%	34%	-	-	-
Allocated - Financial Cost Drivers	29%	34%	15%	-48%	21%
Total*	**100%**	**100%**	**100%**	**100%**	**100%**

*Numbers may not add due to rounding

As noted earlier, OPG also continues to allocate, where applicable, RG Regional Common Costs between regulated and unregulated Cost Allocation Sites. For example, this includes the costs of a Vice President responsible for the Region's overall operations. More granularly, a particular service centre within a Region may perform maintenance on a mix of regulated and unregulated generating facilities. Consistent with the overall cost allocation methodology, OPG uses direct assignment for RG Regional Common Costs to individual generating facilities or groups of similar generating facilities, where reasonably possible. Where use of a cost driver is required, OPG continues to use MCR for the applicable facilities as the basis for allocation. This approach has been in place since it was originally applied by OPG in the EB-2013-0321 proceeding. Elenchus finds the continued use of the MCR allocator to be reasonable and aligned with the cost causality

[12] Shown excluding costs charged through Asset Service Fees.

[13] Direct Assignment may be to the Nuclear business as a whole, an RG Region or to an individual generating facility (or a group of similar generating facilities).

[14] EB-2020-0290 percentages were not computed in Elenchus' previous report.

[15] In the course of this review, OPG and Elenchus identified that the EB-2020-0290 percentage distribution shown in Table 6 of Elenchus' previous review inadvertently included insurance costs under both Corporate Support Services and Centrally-Held Costs. The comparative EB-2020-0290 percentage distribution shown in this report's Table 6 has been corrected. There are no other impacts to Elenchus previous report.

principles. In particular, the use of the allocator recognizes the fact that smaller stations and associated dams require less effort to maintain. Use of MCR also promotes stability in allocation outcomes over time.

A summary of RG Regional Common Costs allocated between regulated and unregulated generating facilities by using the MCR allocator can be found in Table 7 below.

Table 7: RG Regional Common Costs Allocated Across Regulated and Unregulated Facilities using MCR Cost Driver ($M)

RG Regional Common Costs	2027-31 Business Plan (Avg per year)	% of Total
Site and Support Services	$13.1	20%
Operations/Control Centre Common/Water Mgmt.	$14.2	22%
Service / Work Centres:		
Dam Maintenance and Operations	$0	0%
Station Maintenance	$37.6	58%
Total	**$64.9**	**100%**

5 ELENCHUS OPINION

Elenchus finds that OPG's current cost allocation methodology, including the use of asset service fees, is consistent with the methodology reflected in the OPG payment amounts set by the OEB in EB-2020-0290 and as reviewed by Elenchus for that proceeding. Elenchus finds that changes made to the cost allocation methodology since EB-2020-0290 have been minor and that the methodology continues to be reasonable for OPG's business and is aligned with sound cost allocation principles, including through the use of asset service fees. Elenchus finds that the methodology has been appropriately applied based on the Business Plan and is satisfied that, where necessary, it appropriately reflects the introduction of the DNNP and its expected transfer to a new partnership entity.

Elenchus supports the increased use of specific identification in the cost allocation methodology and recommends for OPG to continue evaluating where additional specific identification can be used in place of management estimation in the future. In addition, Elenchus recommends for OPG to enhance its internal written documentation of the cost allocation model and description of its allocation processes.

APPENDIX A – CENTRAL AND COMMON COSTS

Group	Department / Category		Activity % of Department	Department's Distribution to Cost Allocation Sites			
				Direct Assignment		Allocated	
				Method	%	Cost Driver	%
CORPORATE & TECHNOLOGY SERVICES (CTS)	CTS Support	Chief Information Officer Office	0.2%	NA	0.0%	Physical - LAN IDs	0.2%
		Cyber Security	4.9%		0.0%		4.9%
		Enterprise Services	5.9%		0.0%		5.8%
		Application Development	7.3%		0.0%		7.3%
		Customer Experience	9.2%		0.0%		9.2%
		Telecomm/Hardware/Software	40.5%	Management Estimate	0.2%		40.3%
		Information Management Execution	1.0%	Specific / Management Estimate	0.9%		0.1%
		Data Services	2.1%	NA	0.0%		2.1%
		Primary Pay	0.2%		0.0%		0.2%
		Subtotal	*71.3%*		*1.0%*		*70.2%*
	IT Projects		16.3%	Specific / Management Estimate	3.5%	Physical - LAN IDs Financial - OM&A/Capital	12.8%
	Shared Services	Financial Services	3.0%	NA	0.0%	Financial - OM&A/Capital	3.0%
		Pay Services and Support	3.3%		0.0%	Financial - Labour $	3.3%
		HR Service Centre	3.0%		0.0%		3.0%
		Business Information Management	3.1%	Specific	2.4%	Financial - OM&A/Capital	0.7%
		Primary Pay	0.1%	NA	0.0%	Financial - Labour $	0.1%
		Subtotal	*28.7%*		*5.9%*		*22.9%*
		Total	*100.0%*		*6.9%*		*93.1%*
SUPPLY CHAIN	Chief Supply Officer Office		4.2%	NA	0.0%	Financial - OM&A/Capital	4.2%
	Supply Chain Project Support		2.8%	Specific / Management Estimate	2.1%		0.7%
	Quality Assurance		17.3%	Specific	14.5%		2.8%
	Category Management		12.1%		3.9%		8.1%
	Strategic Programs		12.9%	NA	0.0%		12.9%
	Purchasing		13.2%	Specific	10.0%		3.3%
	Plant Operations		36.7%		35.5%		1.2%
	Primary Pay		0.8%	NA	0.0%	Financial - Labour $	0.8%
	Total		*100.0%*		*66.0%*		*34.0%*
REAL ESTATE	VP Office		1.2%	NA	0.0%	Financial - OM&A/Capital	1.2%
	Nuclear Facility Services		44.4%	Specific	44.4%	NA	0.0%
	Real Estate Services		9.2%	Specific/ Management Estimate	8.5%	Financial - OM&A/Capital	0.6%
	Leases and Utilities		27.9%		26.1%		1.8%
	Projects & Accommodations		10.5%	Specific	8.1%		2.5%
	Employee Experience		3.0%	NA	0.0%		3.0%
	Corporate Headquarters		3.5%	Asset Service Fees	3.5%	NA	0.0%
	Wesleyville Property		0.2%	Specific	0.2%		0.0%
	Primary Pay		0.2%	NA	0.0%	Financial - Labour $	0.2%
	Total		*100.0%*		*90.7%*		*9.3%*
FINANCE	Chief Financial Officer and Chief Controller Offices		1.6%	NA	0.0%	Financial - OM&A/Capital	1.6%
	Enterprise Risk Management		1.6%	Management Estimate	0.5%		1.2%
	Internal Audit (incl. VP Office)		10.6%	NA	0.0%		10.6%
	Operations Controllership		23.5%	Specific/ Management Estimate	13.3%		10.2%
	Business Planning & Reporting		13.5%	Management Estimate	1.2%		12.3%
	Income Tax		4.5%	NA	0.0%		4.5%
	External Reporting & Accounting Policy and Audit Fees		12.3%	Specific/ Management Estimate	0.4%		11.9%
	Fund Management		3.4%	NA	0.0%		3.4%
	Commercial Integration and Strategy & New Growth		13.4%	Management Estimate	7.5%		5.9%
	Controllership and Finance Projects & Business Enablement		5.9%	NA	0.0%		5.9%
	Treasury		9.3%	Specific/ Management Estimate	2.3%		6.9%
	Primary Pay		0.4%	NA	0.0%	Financial - Labour $	0.4%
	Total		*100.0%*		*25.2%*		*74.8%*
HUMAN RESOURCES	SVP Human Resources Office		3.9%	NA	0.0%	Financial - Labour $	3.9%
	Compensation & Benefits		8.1%		0.0%		8.1%
	Recruitment & Onboarding		22.3%		0.0%		22.3%
	Labour Relations		12.0%		0.0%		12.0%
	Talent Management & Leadership Development		15.5%		0.0%		15.5%
	HR Projects		0.8%		0.0%		0.8%
	Workforce Planning		4.5%		0.0%		4.5%
	HR Business Partnering		18.0%	Management Estimate	3.5%		14.5%
	Health Services		8.9%	NA	0.0%		8.9%
	Ethics & Equity		5.7%		0.0%	Financial - OM&A/Capital $	5.7%
	Primary Pay		0.2%		0.0%	Financial - Labour $	0.2%
	Total		*100.0%*		*3.5%*		*96.5%*

Group	Department / Category		Activity % of Department	Department's Distribution to Cost Allocation Sites			
				Direct Assignment		Allocated	
				Method	%	Cost Driver	%
CORPORATE CENTRE	Executive Operations	Chief Executive Officer Office	40.9%	NA	0.0%	Financial - OM&A/Capital	40.9%
		Chief Administrative Officer Office	37.5%		0.0%		37.5%
		Chief Commercial Officer Office	21.6%		0.0%		21.6%
		Primary Pay	0.0%		0.0%	Financial - Labour $	0.0%
		Total	*100.0%*		*0.0%*		*100.0%*
	Commercial Management	Commercial Management	100.0%	Specific/ Management Estimate	47.2%	Financial - OM&A/Capital	52.8%
		Total	*100.0%*		*47.2%*		*52.8%*
	Corporate Affairs & Hydro Business Development	Hydro Business Development	3.9%	Specific	3.9%	NA	0.0%
		Indigenous Relations	15.8%		2.9%	Financial - OM&A/Capital	12.8%
		Stakeholder Relations & Government Affairs	80.1%		5.2%		74.8%
		Primary Pay	0.3%	NA	0.0%	Financial - Labour $	0.3%
		Total	*100.0%*		*12.0%*		*88.0%*
	Regulatory Affairs	Regulatory Affairs	60.1%	Management Estimate	18.0%	Financial - OM&A/Capital	42.1%
		Regulatory Proceedings and OEB fees	39.8%		17.9%		21.9%
		Primary Pay	0.1%	NA	0.0%	Financial - Labour $	0.1%
		Total	*100.0%*		*35.9%*		*64.1%*
	Law, Governance & ESG	Law Division	77.2%	Specific/ Management Estimate	22.8%	Financial - OM&A/Capital	54.5%
		Corporate Governance & Corporate Secretary & ESG	22.8%	NA	0.0%		22.8%
		Primary Pay	0.0%		0.0%	Financial - Labour $	0.0%
		Total	*100.0%*		*22.8%*		*77.2%*
	Corporate Business Development & Strategy	Enterprise Strategy	74.7%	Management Estimate	29.8%	Financial - OM&A/Capital	44.9%
		Nuclear Business Development & Strategic Sites	25.1%		25.1%	NA	0.0%
		Primary Pay	0.1%	NA	0.0%	Financial - Labour $	0.1%
		Total	*100.0%*		*55.0%*		*45.0%*
ENVIRONMENT, HEALTH & SAFETY	Environment, Health & Safety		100.0%	Specific	44.8%	Financial - OM&A/Capital	55.2%
	Total		*100.0%*		*44.8%*		*55.2%*
ENTERPRISE ENGINEERING	Chief Enterprise Engineer Office and Industry Membership Fees		10.7%	Specific	10.4%	Financial - Base OM&A	0.3%
	Advanced Inspection and Maintenance		23.5%		19.4%	Financial - OM&A/Capital	4.1%
	Central Engineering		36.4%	Specific / Management Estimate	25.7%	Financial - OM&A/Capital	10.7%
	Design & Project Engineering		11.5%		11.1%	Financial - Base OM&A (RG only)	0.4%
	Station Engineering		17.9%		17.6%	Financial - OM&A/Capital	0.2%
	Total		*100.0%*		*84.3%*		*15.7%*
INTEGRATED FLEET MANAGEMENT	SVP Integrated Fleet Management		1.1%	NA	0.0%	Financial - Base OM&A	1.1%
	Enterprise Learning - Renewable Generation Training		5.2%		0.0%	Financial - Base OM&A (RG only)	5.2%
	Enterprise Learning - Nuclear Training		26.0%	Specific	25.4%	Financial - OM&A/Capital	0.6%
	Fleet Performance		7.5%	Specific / Management Estimate	7.5%	NA	0.0%
	Fleet Performance - Stakeholder Relations		3.6%	Specific	3.6%		0.0%
	Security & Emergency Services (incl. VP Office)		56.6%		56.6%		0.0%
	Total		*100.0%*		*93.1%*		*6.9%*
ENTERPRISE PROJECTS	Renewable Generation Major Projects		18.7%	NA	0.0%	Financial - OM&A/Capital	18.7%
	Nuclear Projects		15.5%	Specific / Management Estimate	15.5%	NA	0.0%
	Enterprise Project Management Office		65.8%	Specific	3.2%	Financial - OM&A/Capital	62.6%
	Total		*100.0%*		*18.8%*		*81.2%*
OTHER OPERATIONS SUPPORT	Chief Nuclear Officer Office		1.9%	Specific	0.7%	Financial - OM&A/Capital	1.2%
	Chief Operations Officer Office		2.1%	Specific / Management Estimate	1.1%		1.0%
	Chief Project Officer Office		0.9%	NA	0.0%		0.9%
	SVP Renewable Generation Office & RG Programs and Strategy		6.5%	Specific	1.8%	Financial - OM&A/Capital (RG Only)	4.7%
	SVP Enterprise Projects Office		3.6%		2.9%	Financial - OM&A/Capital	0.7%
	Commercial Services		1.8%	Management Estimate	1.8%	NA	0.0%
	Nuclear Oversight		5.4%	Specific	5.4%		0.0%
	Nuclear Regulatory Affairs & CNSC Fees		30.3%		30.3%		0.0%
	Nuclear Sustainability Services and Strategy		2.8%	Management Estimate	2.8%		0.0%
	Dam Safety & Water Resources		5.3%	NA	0.0%	Financial - Base OM&A (RG only)	5.3%
	Energy Markets		25.9%	Specific / Management Estimate	7.7%	Financial - OM&A/Capital	18.2%
	Primary Pay		13.5%	NA	0.0%	Financial - Labour $	13.5%
	Total		*100.0%*		*54.5%*		*45.5%*
CENTRALLY HELD	Pension / OPEB Centrally Held		100.0%	Direct Pension Charges	82.5%	Corporate Support Re-Allocation	17.5%
	Total		*100.0%*		*82.5%*		*17.5%*
	Insurance	OPG-Wide Insurance	29.1%	Specific	29.1%	NA	0.0%
		Nuclear Insurance	22.0%		22.0%		0.0%
	Employee Performance Incentives		35.1%	NA	0.0%	Financial - Management Labour $	35.1%
	Other	Fiscal Calendar Adjustment	-0.6%		0.0%	Financial - Labour $	-0.6%
		Vacation Accrual/Banked Time	8.1%		0.0%		8.1%
		Other	6.2%	Specific	1.2%	Financial - OM&A/Capital	5.0%
	Total		*100.0%*		*52.3%*		*47.7%*

Notes:

a) Where Central and Common Costs are directly assigned to the Nuclear business as a whole, rather than to a specific nuclear generating station, the primary cost driver to apportion these costs to each of the sites, as applicable, is the number of Generating Units. Refer to Appendix B for further details.

b) Primary Pay is a cost centre maintained to capture, for administrative purposes, certain types of labour costs not distributed through standard labour rates.

APPENDIX B – REGULATED NUCLEAR BUSINESS DIRECT ASSIGNMENT

Group	Department / Category		Activity % of Department	Distribution of Directly Assigned Costs to Regulated Nuclear Business (from Appendix A)	
				Direct Assignment to Station (via Specific Identification or Management Estimate)	Nuclear Common Allocation (using Generating Units)
CORPORATE & TECHNOLOGY SERVICES (CTS)	CTS Support	Chief Information Officer Office	0.0%	0.0%	0.0%
		Cyber Security	0.0%	0.0%	0.0%
		Enterprise Services	0.0%	0.0%	0.0%
		Application Development	0.0%	0.0%	0.0%
		Customer Experience	0.0%	0.0%	0.0%
		Telecomm/Hardware/Software	0.0%	0.0%	0.0%
		Information Management Execution	12.8%	12.8%	0.0%
		Data Services	0.0%	0.0%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
	Subtotal		*12.8%*	*12.8%*	*0.0%*
	IT Projects		51.5%	9.6%	41.9%
	Shared Services	Financial Services	0.0%	0.0%	0.0%
		Pay Services and Support	0.0%	0.0%	0.0%
		HR Service Centre	0.0%	0.0%	0.0%
		Business Information Management	35.7%	35.7%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
	Subtotal		*87.2%*	*45.3%*	*41.9%*
	Total		*100.0%*	*58.1%*	*41.9%*
SUPPLY CHAIN	Chief Supply Officer Office		0.0%	0.0%	0.0%
	Supply Chain Project Support		3.2%	0.8%	2.5%
	Quality Assurance		22.0%	0.0%	22.0%
	Category Management		5.9%	0.0%	5.9%
	Strategic Programs		0.0%	0.0%	0.0%
	Purchasing		15.1%	7.2%	8.0%
	Plant Operations		53.8%	18.6%	35.2%
	Primary Pay		0.0%	0.0%	0.0%
	Total		*100.0%*	*26.5%*	*73.5%*
REAL ESTATE	VP Office		0.0%	0.0%	0.0%
	Nuclear Facility Services		57.7%	57.7%	0.0%
	Real Estate Services		5.7%	0.0%	5.7%
	Leases and Utilities		26.1%	10.4%	15.7%
	Projects & Accommodations		10.5%	5.2%	5.3%
	Employee Experience		0.0%	0.0%	0.0%
	Corporate Headquarters		0.0%	0.0%	0.0%
	Wesleyville Property		0.0%	0.0%	0.0%
	Primary Pay		0.0%	0.0%	0.0%
	Total		*100.0%*	*73.3%*	*26.7%*
FINANCE	Chief Financial Officer and Chief Controller Offices		0.0%	0.0%	0.0%
	Enterprise Risk Management		3.9%	3.9%	0.0%
	Internal Audit (incl. VP Office)		0.0%	0.0%	0.0%
	Operations Controllership		96.1%	49.6%	46.5%
	Business Planning & Reporting		0.0%	0.0%	0.0%
	Income Tax		0.0%	0.0%	0.0%
	External Reporting & Accounting Policy and Audit Fees		0.0%	0.0%	0.0%
	Fund Management		0.0%	0.0%	0.0%
	Commercial Integration and Strategy & New Growth		0.0%	0.0%	0.0%
	Controllership and Finance Projects & Business Enablement		0.0%	0.0%	0.0%
	Treasury		0.0%	0.0%	0.0%
	Primary Pay		0.0%	0.0%	0.0%
	Total		*100.0%*	*53.5%*	*46.5%*
HUMAN RESOURCES	SVP Human Resources Office		0.0%	0.0%	0.0%
	Compensation & Benefits		0.0%	0.0%	0.0%
	Recruitment & Onboarding		0.0%	0.0%	0.0%
	Labour Relations		0.0%	0.0%	0.0%
	Talent Management & Leadership Development		0.0%	0.0%	0.0%
	HR Projects		0.0%	0.0%	0.0%
	Workforce Planning		0.0%	0.0%	0.0%
	HR Business Partnering		100.0%	100.0%	0.0%
	Health Services		0.0%	0.0%	0.0%
	Ethics & Equity		0.0%	0.0%	0.0%
	Primary Pay		0.0%	0.0%	0.0%
	Total		*100.0%*	*100.0%*	*0.0%*

Group	Department / Category		Activity % of Department	Distribution of Directly Assigned Costs to Regulated Nuclear Business (from Appendix A)	
				Direct Assignment to Station (via Specific Identification or Management Estimate)	Nuclear Common Allocation (using Generating Units)
CORPORATE CENTRE	Executive Operations	Chief Executive Officer Office	0.0%	0.0%	0.0%
		Chief Administrative Officer Office	0.0%	0.0%	0.0%
		Chief Commercial Officer Office	0.0%	0.0%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
		Total	*0.0%*	*0.0%*	*0.0%*
	Commercial Management	Commercial Management	100.0%	57.6%	42.4%
		Total	*100.0%*	*57.6%*	*42.4%*
	Corporate Affairs & Hydro Business Development	Hydro Business Development	0.0%	0.0%	0.0%
		Indigenous Relations	28.3%	28.3%	0.0%
		Stakeholder Relations & Government Affairs	71.7%	0.0%	71.7%
		Primary Pay	0.0%	0.0%	0.0%
		Total	*100.0%*	*28.3%*	*71.7%*
	Regulatory Affairs	Regulatory Affairs	42.5%	42.5%	0.0%
		Regulatory Proceedings and OEB fees	57.5%	57.5%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
		Total	*100.0%*	*100.0%*	*0.0%*
	Law, Governance & ESG	Law Division	100.0%	0.0%	100.0%
		Corporate Governance & Corporate Secretary & ESG	0.0%	0.0%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
		Total	*100.0%*	*0.0%*	*100.0%*
	Corporate Business Development & Strategy	Enterprise Strategy	0.0%	0.0%	0.0%
		Nuclear Business Development & Strategic Sites	0.0%	0.0%	0.0%
		Primary Pay	0.0%	0.0%	0.0%
		Total	*0.0%*	*0.0%*	*0.0%*
ENVIRONMENT, HEALTH & SAFETY	Environment, Health & Safety		100.0%	3.7%	96.3%
	Total		*100.0%*	*3.7%*	*96.3%*
ENTERPRISE ENGINEERING	Chief Enterprise Engineer Office and Industry membership Fees		13.4%	0.0%	13.4%
	Advanced Inspection and Maintenance		25.1%	9.1%	16.0%
	Central Engineering		33.2%	22.4%	10.8%
	Design & Project Engineering		14.3%	13.9%	0.5%
	Station Engineering		13.9%	13.7%	0.2%
	Total		*100.0%*	*59.1%*	*40.9%*
INTEGRATED FLEET MANAGEMENT	SVP Integrated Fleet Management		0.0%	0.0%	0.0%
	Enterprise Learning - Renewable Generation Training		0.0%	0.0%	0.0%
	Enterprise Learning - Nuclear Training		27.5%	21.5%	6.0%
	Fleet Performance		8.2%	6.0%	2.1%
	Fleet Performance - Stakeholder Relations		3.9%	0.0%	3.9%
	Security & Emergency Services (incl. VP Office)		60.4%	44.1%	16.3%
	Total		*100.0%*	*71.7%*	*28.3%*
ENTERPRISE PROJECTS	Renewable Generation Major Projects		0.0%	0.0%	0.0%
	Nuclear Projects		82.7%	82.7%	0.0%
	Enterprise Project Management Office		17.3%	17.3%	0.0%
	Total		*100.0%*	*100.0%*	*0.0%*
OTHER OPERATIONS SUPPORT	Chief Nuclear Officer Office		1.4%	0.0%	1.4%
	Chief Operations Officer Office		2.3%	0.0%	2.3%
	Chief Project Officer Office		0.0%	0.0%	0.0%
	SVP Renewable Generation Office & RG Programs and Strategy		0.0%	0.0%	0.0%
	SVP Enterprise Projects Office		6.2%	6.2%	0.0%
	Commercial Services		3.8%	3.8%	0.0%
	Nuclear Oversight		11.5%	0.1%	11.4%
	Nuclear Regulatory Affairs & CNSC Fees		64.1%	53.9%	10.2%
	Nuclear Sustainability Services and Strategy		6.0%	6.0%	0.0%
	Dam Safety & Water Resources		0.0%	0.0%	0.0%
	Energy Markets		4.8%	2.7%	2.0%
	Primary Pay		0.0%	0.0%	0.0%
	Total		*100.0%*	*72.6%*	*27.4%*
CENTRALLY HELD	Pension / OPEB Centrally Held		100.0%	100.0%	0.0%
	Total		*100.0%*	*100.0%*	*0.0%*
	Insurance	OPG-Wide Insurance	22.1%	22.1%	0.0%
		Nuclear Insurance	77.9%	77.4%	0.5%
	Employee Performance Incentives		0.0%	0.0%	0.0%
	Other	Fiscal Calendar Adjustment	0.0%	0.0%	0.0%
		Vacation Accrual/Banked Time	0.0%	0.0%	0.0%
		Other	0.0%	0.0%	0.0%
	Total		*100.0%*	*99.5%*	*0.5%*

APPENDIX C - ORGANIZATIONAL CHANGES

Department / Category	EB-2020-0290 Group	2025 Business Plan Group
Ethics & Equity	Corporate Centre - Law	Human Resources
Commercial Management	Part of Project Assurance and Contract Management	Corporate Centre - Commercial Management
Security & Training	Security & Training	Integrated Fleet Management - Security & Emergency Services
Environment, Health & Safety	Environment, Health & Safety (Corporate Support)	Environment, Health & Safety (Operations Support)
Nuclear Training	Security & Training	Integrated Fleet Management
Nuclear Oversight	Integrated Fleet Management	Other Operations Support
Nuclear Regulatory Affairs	Integrated Fleet Management	Other Operations Support
Renewable Generation Training	Other Operations Support	Integrated Fleet Management
Employee Experience	Corporate Centre - Corporate Communications	Real Estate
Controllership and Finance Projects & Business Enablement	Partially part of Operations Controllership	Finance - Controllership and Finance Projects & Business Enablement
Health Services	Environment, Health & Safety	Human Resources – Health Services
HR Business Partnering	Nuclear Stations & Project HR Support and Corporate & RG HR Support.	Human Resources – HR Business Partnering
Commercial Integration and Strategy & New Growth	Part of Corporate Business Development & Strategy	Finance - Commercial Integration and Strategy & New Growth

APPENDIX D - CVS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for over 45 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 300 proceedings and provided expert evidence in over 175 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Elenchus (Econalysis) Consulting Services, Inc. (ECS) **1980**

- ECS was divested as a separate company in 2003

EDUCATION

1975 Masters of Business Administration (Economics and Management Science), University of Toronto

1972 Bachelors of Applied Science (Electrical Engineering), University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**

Research Assistant, Univ. of Toronto, Faculty of Management Studies **1973 - 1978**

Bell Canada, Western Area Engineering **1972 – 1973**

REGULATORY/LEGAL PROCEEDINGS

Before the Ontario Energy Board

John Todd has provided expert assistance in more than 65 proceedings before the Ontario Energy Board from 1991 to 2024. He has presented evidence in more than 25 of these cases. Recent cases include rate applications for the EPCOR Natural Gas LP (and the predecessor company NRG) and evidence on the *Cost Allocation and Rate Design for the IESO Usage Fee* for the Independent Electricity System Operator.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 50 proceedings before the Public Utilities Board of Manitoba from 1990 to 2025. He has presented evidence in 23 of these cases. He was retained by the Manitoba Public Utilities Board as an Independent expert consultant to review aspects of Manitoba Hydro's Needs for and Alternatives to (NFAT) its Preferred Development Plan. He also served as a Board advisor on several matters in recent years.

Before the British Columbia Utilities Commission

John has provided expert assistance in more than 30 proceedings before the British Columbia Utilities Commission from 1993 to 2025. He has presented evidence in twelve cases. Recently he was retained (with Michael Roger) by the BCUC as its independent expert consultant to review FortisBC Energy Inc. cost allocation and rate design methodology.

Before the Régie de l'énergie

John has provided expert assistance in more than a dozen proceedings before the Régie de l'énergie from 1998 to 2022. He has presented evidence in nine of these cases. He was retained with Cynthia Chaplin to prepare *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.* He is currently engaged in another cost allocation review project for the Régie as an independent expert reviewing the cost allocation methodology of Energir.

Before the Alberta Utilities Commission (and formerly the Alberta Energy and Utilities Board)

John has provided expert assistance in of five proceedings before the Alberta Utilities Commission and its predecessor since 2000. In 2020 he was engaged for rate design work by an Alberta utility.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2021. He has presented evidence most recently in Newfoundland Power's 2022 Capital Budget Application.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of ten proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2025. He has presented evidence in three cases. Recent proceedings he participated in were *General Rate Applications involving reviews of* NB Power's cost allocation methodology and rate design issues.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of ten proceedings before the Nova Scotia Utility and Review Board from 2008 to 2025. He has presented evidence in four cases. The most recent work related to Nova Scotia Power's cost of service study.

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2020. He has presented evidence in 13 of these cases. The participated in a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134* and prepared evidence was filed in the current Review of the Approach to Rate Setting for Wholesale Telecommunications Services (CRTC 2020-131).

Before the Ontario Securities Commission

John provided expert assistance on behalf of the Director of Investigation and Research, Combines Investigation Act in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case including evidence on Industry structure and the form of regulation in the OSC's *Securities Industry Review.*

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy. John (with Michael Roger) has also conducted the two most recent reviews of SaskPower's cost allocation methodology and presented the results to the Saskatchewan Rate Review Panel.

Non-Hearing Processes

John has provided expert assistance more than a dozen non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in nine commercial arbitrations and lawsuits between 2004 and 2025.

Facilitation Activities

John has undertaken numerous strategic planning and visioning sessions (some with co-facilitators) for the Executive and/or Board of Directors of regulated companies between 2000 and 2020. He has also facilitated six stakeholder processes for regulators and utilities from 2000 through 2025.

Other Regulatory Issues Researched

John has completed (with collaborators in some cases) over 20 studies for industry associations, regulators, utilities and other entities outside of hearing processes

SELECTED PRESENTATIONS

- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Comm. & Regulatory Innovations Task Group (June 2016)
- Productivity Benchmarking Panel at the CEA Electric Utility Workshop (May 2016)
- Funding Utility Innovation at the CEA Electric Utility Workshop (May 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (several years)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2020
- “Innovations in Rate Design”, CAMPUT Training Session, Annually 2010-2013
- “Cost of Service Filing Requirements” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the OEB
- “Green Energy Act” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- “Rate Design”, CAMPUT Training Session, Annually 2009- 2013
- “How to Build Transmission and Distribution to Enable FiT: The Role of Distributors”, EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- “Distributor Mergers and Acquisitions: Potential Savings”, 2007 Electricity Distributors Assoc.
- “Beyond Borders” Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Former invited participant in the Ontario Energy Board’s External Advisory Committee.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over seventy private sector companies, including regulated utilities

Fifteen industry and other associations

Over thirty 30 consumers' associations and legal clinics

Government

- Five Regulatory Tribunals
- Six Federal departments
- Fourteen Provincial departments, commissions and agencies
- Thirteen municipal and other departments/entities

IAN R. INNIS

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SENIOR CONSULTANT

Ian is a finance professional with extensive experience in electrical utility regulation, business planning, budgeting, reporting, internal control and project management. Ian has well-developed interpersonal, organizational and analytical skills and is a proven team player and problem solver who consistently delivers quality results.

PROFESSIONAL OVERVIEW

Elenchus Research Associates Inc. **November 2012 - Present**
Associate

- Provides strategic advice and guidance to LDCs on regulatory issues
- Develops and delivers utility financial and regulatory training
- Provides strategic advice, guidance and support with respect to utility Cost of Service and Incentive Rate Mechanism applications
- Provides analysis and support for utility cost allocation methodology and compliance with Affiliate Relationships Code
- Provides business financial accounting and reporting services

Horizon Utilities **August 2011 – May 2012**

Director – Regulatory Services

- Successfully prepared and managed 2012 Electricity Distribution Rates Incentive Regulation Mechanism (IRM) application, including a Lost Revenue Adjustment Mechanism (LRAM) submission for Conservation and Demand Management (CDM) related impacts
- Successfully prepared and defended a multi-year Smart Meter Prudency Application with 100% recovery of submitted costs

- Managed ongoing regulatory filing and reporting requirements. Submissions made on time, consistent with requirements.
- Managed staff and developed a cohesive team

Hydro One Networks Inc. **2009 – July 2011**
Senior Regulatory Advisor, Regulatory Affairs

- Case manager for Hydro One Distribution 2011 Cost of Service Application (COS) update
- Corporate advisor for Hydro One Brampton 2011 COS Application
- Corporate advisor for Hydro One Remote Communities 2011 IRM Application
- Managed financial evidence in the 2010/11 Hydro One Distribution COS Application (case strategy, evidence preparation, responding to interrogatories, managing issues, training witnesses, responding to undertakings, preparing argument and draft rate orders)
- Represented Hydro One on the EDA Regulatory Council. Work involved assessing industry issues, developing positions/strategy and influencing policy direction
- Developed company responses to regulatory issues and communicated with the OEB in order to influence direction and achieve favourable outcomes (e.g. funding recovery for low income customers)
- Coordinated and submitted timely and accurate quarterly and annual Reporting and Record Keeping Requirement filings to the OEB
- Established accounting processes and controls for new deferral and variance accounts to comply with OEB direction and accounting standards (e.g. Smart Grid rate adder and accounting process)
- Prepared and delivered presentations on Hydro One Distribution and Transmission revenue requirement and rate impacts to large customer groups and stakeholders

Hydro One Networks Inc. **2001 - 2009**
Acting Director/Senior Manager/Manager, Regulatory Finance, Corporate Finance

- Corporate Finance Witness for the OEB in four major Cost of Service Rate Applications. Work included case strategy, evidence preparation, issues management, providing oral testimony as a witness at OEB proceedings and interpreting and implementing financial aspects of rate decisions
- Scope of oral testimony included defending Transmission Revenue Requirement ($1.2B), Transmission Rate Base ($7.5B), Distribution Revenue Requirement ($1.0B), Distribution Rate Base ($4.2B), Corporate Functions and Services costs, Cost Allocation, Working Capital, Overhead Capitalization and disposition of Regulatory Assets

- Company witness at Smart Meter oral hearing regarding prudency of expenditures and account disposition
- Monitored and interpreted emerging issues and engaged in industry forums to establish regulatory requirements
- Assessed and managed regulatory issues to meet Corporate and statutory requirements
- Developed and implemented reporting infrastructure to provide accurate quarterly and annual statutory filing requirements with the OEB (e.g. USofA, RRR filings)
- Managed business planning issues and integrated business planning results into rate filings, including accountability for the regulatory financial reference base
- Represented Hydro One on EDA Finance Council (work involved assessing industry issues, developing positions/strategy and influencing policy direction)
- Received two "Presidents Awards" for work on regulatory filings, recognizing quality of submissions and successful defense before the OEB

Ontario Hydro/Hydro One Networks Inc. **1999 - 2001**
Manager, Finance – Network Management

- Established reporting process and infrastructure to enable monthly management reporting consistent with approved budget and rate order
- Coordinated multiple budget mappings as a result of evolving business requirements during transition from Ontario Hydro Transmission to Ontario Hydro Services Company to Hydro One
- Participated in the development of Hydro One's credit rating filings and first prospectus
- Prepared monthly and annual financial reports for $1Billion+ Operating and Capital budgets

Ontario Hydro **1997 - 1999**
Manager, Planning and Reporting - Transmission

- Managed the business planning and budgeting process. Work included developing a planning process, preparing instructions and requirements, presentations to line groups and resolution of issues, integration of submitted plans, preparation of consolidated business plan document for senior management approval and coordination and integration of budget detail (annual and monthly) to ensure timely management decision making
- Developed an infrastructure to support work program based reporting and reconciliation to Corporate accounts
- Coordinated financial information submitted for the first Hydro One rate filing when no systems or history existed. Subsequently developed methodologies and built systems to report expenditures against approved levels

Ontario Hydro **1993 - 1997**
Financial Services Manager - Hydroelectric

- Responsible for accounting, financial systems and internal control
- Established accounting and financial systems infrastructure for newly created group
- Developed and prepared monthly financial reports (full financial statements, work program reports)
- Prepared Hydroelectric Annual Report

Responsibilities prior to above include various analyst, senior analyst and advisory positions at the Corporate and Operating Branch levels. Work included a full range of financial support responsibilities such as planning, budgeting, accounting, internal control and financial systems development.

ACADEMIC ACHIEVEMENTS

1980	Bachelor of Commerce, McMaster University, Hamilton, Ontario • Finance and Accounting Major
1983	Certified Management Accountant, Society of Management Accountants [Currently CPA, CMA Chartered Professional Accountants of Ontario]

ANDREW BLAIR

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SENIOR CONSULTANT

Andrew Blair has ten years of experience as a research analyst and consultant in electricity and gas utility price regulation. He regularly prepares load forecasts for electricity and natural gas utility cost of service applications in Ontario and provides cost allocation and rate design support to utilities across Canada.

Andrew regularly prepares models, reports, and other written evidence for utility public application filings. He has appeared before the New Brunswick Energy & Utilities Board as New Brunswick Power's cost allocation subject matter expert in annual general rate applications and has appeared before the Ontario Energy Board as a witness for distributor load forecasting and on an expert panel on transmission cost allocation. Andrew has created and developed cost allocation and rate design models, including for Monserrat Utilities and Ontario's Independent Electricity System Operator. He is an instructor in MEARIE's Regulatory Specialist Certificate program in the area of load forecasting, cost allocation, and rate design. He previously worked for the Ontario provincial government over a seven-year period as a trust analyst and a trust accountant. Andrew has a Master's Degree in Economics from Carleton University and a Bachelor's Degree in Economics and Financial Management from Wilfrid Laurier University.

PROFESSIONAL OVERVIEW

Elenchus Research Associates **January 2016 - Present**
Senior Consultant

- Prepare load forecasts for electricity and natural gas utilities
- Design and prepare cost allocation and rate design models and evidence
- Research regulatory filings and common practices across jurisdictions and regulators
- Provide research and modeling support for economic feasibility studies
- Prepare evidence, interrogatories, cross-examination, and submissions for regulatory hearings

Office of the Public Guardian and Trustee **May 2012 – June 2013**
Trust Analyst **Summers 2010 & 2011**

- Designed estate allocation and payment disbursement system
- Summarized and analyzed aggregate account information
- Allocated interest and fees to close out accounts
- Researched Public Guardian clients' files and family histories to determine estate beneficiaries
- Located beneficiaries and distributed estates

EDUCATION

June 2014	Master of Arts, Economics, Carleton University
June 2012	Bachelor of Arts, Economics and Financial Management, Wilfrid Laurier University

REGULATORY/LEGAL PROCEEDINGS

Before the Ontario Energy Board

2025	• Burlington Hydro 2025 Cost of Service Application (with Power Advisory) (Company evidence: load forecast, support on cost allocation and rate design) • Oshawa Power 2025 Cost of Service Application (Company evidence: load forecast, support on cost allocation and rate design)
2024	• Essex Powerlines 2025 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • Greater Sudbury Hydro 2025 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design)
2023	• Synergy North, 2024 Cost of Service Application (Company evidence: load forecast, cost allocation, rate harmonization, and rate design)
2022	• Hydro One Networks, 2023-2027 Joint Distribution and Transmission Rates (Evidence: Export Transmission Service Rate Cost Allocation Methodology) • Independent Electricity System Operator, 2022 Usage Fee (Evidence: IESO Cost Allocation Methodology Review) • Utilities Kingston, 2023 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • Bluewater Power, 2023 Cost of Service Application (Company evidence: LRAMVA, load forecast, cost allocation, and rate design) • EPCOR Electricity Distribution Ontario, 2023 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • Milton Hydro, 2023 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design)
2021	• Grimsby Power Inc., 2022 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • E.L.K. Energy, 2022 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design)

2020	• Hydro Ottawa, 2021-2026 Custom IR Application (Company evidence: cost allocation and rate design) • Lakeshore Communities, LTC and Phase II Applications for new natural gas utility • Halton Hills Hydro, 2021 Cost of Service Application (Company evidence: lost revenue adjustment mechanism variance account; assistance with load forecast, cost allocation, and rate design)
2019	• Burlington Hydro, 2021 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • Greater Sudbury Hydro, Cost of Service Application (Company evidence: lost revenue adjustment mechanism variance account, load forecast, cost allocation, and rate design)
2017	• Erie Thames Powerlines, 2018 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design) • Essex Powerlines, 2018 Cost of Service Application (Company evidence: load forecast, cost allocation, and rate design)

Before the New Brunswick Energy and Utilities Board

2024	• New Brunswick Power, 2023-24 & 2024-25 General Rate Application (Evidence: Overview Report on NB Power's Proposed Regulatory Accounts) • New Brunswick Power, 2024 Cost Allocation Methodology Proceeding (Evidence: CCAS Generation Classification and Allocation Methodology Options)
2022	• New Brunswick Power, Rate Design Review (Evidence: NB Power's Cost Allocation for Street Light & Unmetered Service)
2019	• New Brunswick Power, 2020-21 General Rate Application (Company evidence: cost allocation)
2018	• New Brunswick Power, 2019-20 General Rate Application (Evidence: New Brunswick Power Class Cost Allocation Study Update for the 2019-20 GRA. Company evidence: cost allocation)
2017	• New Brunswick Power, 2018-19 General Rate Application (Evidence: New Brunswick Power Class Cost Allocation Study Update for the 2018-19 GRA. Company evidence: cost allocation)

Non-Hearing Processes

2023	• Ontario Energy Board, Electric Delivery Rates for Electric Vehicle Charging (with Power Advisory) • SaskPower, Review of SaskPower Cost Allocation and Rate Design Methodologies
2020	• EfficiencyOne, Rate and Bill Impact Analysis of DSM Programs
2019	• Montserrat Utilities Ltd., Cost of Service and Tariff Study led by HATCH