November 23, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0307 – Enbridge Gas Distribution Inc. and Union Gas Limited – Rate Setting Mechanism – Application and Evidence

On November 2, 2017 Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") filed for approval to amalgamate and to defer rate rebasing from 2019 to 2029 ("deferred rebasing period") under EB-2017-0306. Please see the attached for the Application and Evidence to the Ontario Energy Board ("OEB") seeking approval of the rate setting mechanism and associated parameters during the deferred rebasing period, under Section 36 of the *Ontario Energy Board Act, 1998*.

To assist the OEB, EGD and Union have included a draft issues list in Exhibit A, Tab 3.

The evidence is organized as follows:

<u>Exhibit A</u>

Tab 1: Exhibit List
Tab 2: Application
Tab 3: Draft Issues List

<u>Exhibit B</u>

Tab 1: Rate Setting Mechanism Evidence
Tab 2: National Economic Research Associates Inc. – Expert Report and Direct Testimony

If you have any questions on this matter, please contact me at 519-436-5334.

Sincerely,

[*original signed by*]

Vanessa Innis
Manager, Regulatory Applications

cc: Andrew Mandyam, EGD
Mark Kitchen, Union
Fred Cass, Aird & Berlis
Crawford Smith, Torys
EB-2016-0245 and EB-2016-0215 Intervenors

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED
RATE SETTING MECHANISM APPLICATION
EXHIBIT LIST

Exh.	Tab	Attachment	Contents
A			
	1		Exhibit List
	2		Application
	3		Draft Issues List
B			
	1		Rate Setting Mechanism Evidence
		1	Certification of Evidence
		2	Amalco OEB Scorecard
		3	List of Existing Deferral Accounts
		4	List of Deferral Accounts to be Continued During Deferred Rebasing Period
		5	Response to Board Directives and Commitments
	2		National Economic Research Associates Inc. - Expert Report and Direct Testimony

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 36 of the *Ontario Energy Board Act, 1998*, for an order or orders approving a rate setting mechanism and associated parameters during the deferred rebasing period, effective January 1, 2019.

APPLICATION

1. Enbridge Gas Distribution Inc. ("EGD") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario.

2. Union Gas Limited ("Union") is a business corporation incorporated under the laws of the Province of Ontario, with its head office in the Municipality of Chatham-Kent. Union conducts both an integrated natural gas utility business that combines the operations of distributing, transmitting and storing natural gas, and a non-utility storage business.

3. EGD is operating under a five year Incentive Regulation ("IR") plan approved by the Ontario Energy Board ("OEB" or the "Board") in EB-2012-0459. The Board Decision with Reasons in that proceeding establishes a Custom IR framework to set EGD's rates over the period from 2014 to 2018.

4. Union is operating under a five year Incentive Rate Mechanism ("IRM") approved by the Board in EB-2013-0202. The Board's Decision with Reasons in that proceeding approved

a price cap IRM to set Union's rates for the regulated distribution, transmission and storage of natural gas over the period from 2014 to 2018.

5. EGD and Union (collectively "the Applicants") applied to the OEB, pursuant to section 43 of the OEB Act for an order or orders granting leave to amalgamate effective January 1, 2019 in EB-2017-0306.

6. The Applicants hereby apply to the OEB, pursuant to section 36 of the Ontario Energy Board Act for an order approving a rate setting mechanism and associated parameters for the deferred rebasing period, effective January 1, 2019. The Applicants seek a rate setting mechanism in which:
   a. the annual rate escalation is determined by a price cap index ("PCI"), where PCI growth is driven by an inflation factor, less a productivity factor of zero and no stretch factor;
   b. exists for 10 years (the deferred rebasing period);
   c. continues to pass-through routine gas commodity and upstream transportation costs, demand side management cost changes, lost revenue adjustment mechanism changes for the contract market, normalized average consumption/average use, and Cap-and-Trade costs; and
   d. allows for non-routine cost adjustments for matters outside of the Applicants' control with a materiality threshold of $1.0 million.

7. The Applicants further apply to the OEB for approval of the following parameters in calculating treatment of qualifying capital investments through the OEB's Incremental Capital Module:
   a. Based on separate materiality threshold calculations using rate base and depreciation expense approved in 2013 rates for Union and 2018 rate for EGD
   b. Using incremental cost of capital to calculate the revenue requirement to fund incremental capital investment

i. 64/36 debt to equity ratio
ii. incremental cost of long-term debt issued
iii. allowed return on equity ("ROE") based on the OEB's cost of capital formula for the year the investment is placed in service

8. The Applicants further apply to the OEB for approval of an adjustment of $17.4 million pre-tax ($12.8 million after-tax) to Union's 2018 Board-approved revenue reflecting the full amortization of the accumulated deferred tax balance at the end of 2018

9. The Applicants further apply to the OEB for approval of an adjustment of $4.9 million to EGD's 2018 Board-approved revenue reflecting smoothing of costs related to EGD's Customer Information System and customer care forecast costs

10. The Applicants further apply for the continuation of certain existing deferral and variance accounts and the discontinuation of the following deferral and variance accounts:

EGD

179.16_	Customer Care CIS Rate Smoothing Deferral Account
179.34_	Constant Dollar Net Salvage Adjustment Deferral Account
179.96_	Relocations Mains Variance Account
179.98_	Replacement Mains Variance Account
179.24_	Post-Retirement True-up Variance Account
179.58_	Earnings Sharing Mechanism Deferral Account

Union

179-120	CGAAP to IFRS Conversion Costs
179-134	Tax Variance Deferral Account

11. This application is supported by written evidence and may be amended from time to time as circumstances require.

12. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by the Applicants, together with those to whom the Applicants sell gas, or on whose behalf the Applicants distribute, transmit or store natural gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

13. The address of service for the Applicants is:

Enbridge Gas Distribution

Address for personal service:
500 Consumers Road
Willowdale, Ontario M2J 1P8

Mailing address:
P. O. Box 650
Scarborough, Ontario M1K 5E3

Attention:	Andrew Mandyam Director, Regulatory Affairs
Telephone:	(416) 495-5499
Fax:	(416) 495-6072

- and -

Union Gas Limited

P.O. Box 2001
50 Keil Drive North
Chatham, Ontario N7M 5M1

Attention: Mark Kitchen
Director, Regulatory Affairs
Telephone: (519) 436-5275
Fax: (519) 436-4641

- and -

Aird & Berlis LLP
Suite 1800, P.O. Box 754
Brookfield Place, 181 Bay Street
Toronto, Ontario M5J 2T9

Attention: Fred D. Cass
Telephone: (416) 865-7742
Fax: (416) 863-1515

DATED November 23, 2017.

ENBRIDGE GAS DISTRIBUTION INC.
UNION GAS LIMITED

Fred D Cass

Fred D. Cass
Aird & Berlis LLP

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

RATE SETTING MECHANISM APPLICATION

DRAFT ISSUES LIST

1. Is the proposed inflation factor appropriate?
2. Is the proposed X factor appropriate?
3. Is the proposed Y factor treatment appropriate?
    a. Continued pass-through of routine gas commodity and upstream transportation costs, demand side management cost changes, lost revenue adjustment mechanism changes for the contract market, Cap-and-Trade costs and normalized average consumption/average use
4. Is the proposed Z factor and associated materiality threshold of $1.0 million appropriate?
5. Is the proposed adjustment to reflect the full amortization of Union's accumulated deferred tax balance at the end of 2018 appropriate?
6. Is the proposed adjustment to unwind smoothing of costs related to EGD's Customer Information System and customer care forecast costs appropriate?
7. Are the proposed deferral and variance accounts appropriate?
8. Should the following deferral accounts be discontinued as proposed?

EGD

179.16_	Customer Care CIS Rate Smoothing Deferral Account
179.34_	Constant Dollar Net Salvage Adjustment Deferral Account
179.96_	Relocations Mains Variance Account
179.98_	Replacement Mains Variance Account
179.24_	Post-Retirement True-up Variance Account

179.58_	Earnings Sharing Mechanism Deferral Account
Union	
179-120	CGAAP to IFRS Conversion Costs
179-134	Tax Variance Deferral Account

9. Is the proposed scorecard appropriate?

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

RATE SETTING MECHANISM EVIDENCE

TABLE OF CONTENTS

1. APPLICATION OVERVIEW

On November 2, 2017 Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") filed for approval to amalgamate and to defer rate rebasing from 2019 to 2029 ("deferred rebasing period") under EB-2017-0306 ("Amalgamation Application"). Collectively EGD and Union are referred to as the "Applicants" and the amalgamated company is referred to as "Amalco." This is an application ("Application") to the Ontario Energy Board ("OEB" or the "Board") under Section 36 of the OEB Act for approval of the rate setting mechanism and associated parameters during the deferred rebasing period.

In preparing both the Amalgamation Application and this Application, the Applicants have been guided by the OEB's Handbook to Electricity Distributor and Transmitter Consolidations ("Consolidation Handbook"), which provides guidance on applications for mergers, acquisitions, amalgamations and divestures ("MAADs"). Although the Consolidation Handbook is directed to the electricity sector, the underlying principles are the same in the gas sector. In the Handbook to Utility Rate Applications[1], the Board outlines how the Renewed Regulatory Framework ("RRF") and its underpinning principles apply to all regulated utilities going forward. The Consolidation Handbook states "rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB."[2]

[1] OEB Handbook to Utility Rate Applications, October 13, 2016.
[2] OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, p.11.

The Applicants will set rates for 2018 using their existing Board-approved Incentive Rate ("IR") mechanisms, which expire at the end of 2018. EGD filed its 2018 Rates Application in accordance with its Custom IR in EB-2017-0086 and Union filed its 2018 Rates Application in accordance with its Price Cap IR in EB-2017-0087. The Consolidation Handbook states:

> *" • a distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.*
> *• a distributor on Custom IR, whose plan expires, would move to having rates based on Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period."*[3]

The price cap parameters for the electricity distributors are described in the Handbook for Utility Rate Applications ("Rate Handbook") [4] and are referred to as Price Cap IR. The parameters include a formulaic annual adjustment mechanism to change the price of regulated services and an Incremental Capital Module ("ICM") to address incremental capital investment needs. Within the formula the Board calculates the inflation factor and assigns distributors to efficiency cohorts in order to determine a company-specific productivity, or stretch factor. The industry-specific productivity factor is zero[5]. As the Applicants are not part of this annual Board process, this Application proposes an inflation factor and productivity factor that are modelled on Price Cap IR.

[3] Ibid, p.14.
[4] Handbook for Utility Rate Applications, October 13, 2016.
[5] EB-2010-0379 Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, November 21, 2013, p. 17.

The Applicants will maintain the existing rate zones (EGD, Union North, and Union South) during the deferred rebasing period. The rate zone of new customers will be defined by the franchise area under which the customer would have been served prior to amalgamation.

In this Application the Applicants seek the following specific approvals:

1. A multi-year incentive rate mechanism ("IRM") to determine rates for the regulated distribution, transmission and storage of gas for the period 2019 through 2028 including:
    a. An annual rate change calculation using a price cap index ("PCI"), where PCI growth is driven by an inflation factor, less a productivity factor of zero and no stretch factor;
    b. Continued pass-through of routine gas commodity and upstream transportation costs, demand side management cost changes, lost revenue adjustment mechanism changes for the contract market, normalized average consumption/average use, and Cap-and-Trade costs;
    c. The ability to address material changes in costs associated with unforeseen events outside of the control of management. The Applicants propose a materiality threshold of $1.0 million, which is consistent with the threshold for electric distributors;[6]

[6] Filing Requirements for Electricity Distribution Rate Applications, July 14, 2016 at Section 2.0.8 (Materiality Thresholds) sets a materiality threshold of $1 million for a distributor with a distribution revenue requirement of more than $200 million.

2. Recovery through rates for qualifying incremental capital investments through the Board-approved ICM:
    a. Based on separate materiality threshold calculations using rate base and depreciation expense last approved by the Board (2013 rates for Union and 2018 rates for EGD);
    b. Using incremental cost of capital to calculate the revenue requirement to fund incremental capital investment:
        i. 64/36 debt to equity ratio;
        ii. incremental cost of long-term debt issued;
        iii. allowed return on equity ("ROE") based on the OEB's cost of capital formula for the year the investment is placed in service;
3. An adjustment of $17.4 million pre-tax ($12.8 million after-tax) to increase Union's 2018 Board-approved revenue reflecting the full amortization of the accumulated deferred tax balance at the end of 2018;
4. An adjustment of $4.9 million to decrease EGD's 2018 Board-approved revenue reflecting smoothing of costs related to EGD's Customer Information System and customer care forecast costs;
5. Continuation of certain existing deferral and variance accounts, and discontinuation of others.

The Applicant's evidence is accurate, consistent and complete. The certification of evidence is provided at Exhibit B, Tab 1, Attachment 1. The evidence supporting this Application includes the following sections:

1. **Application Overview**
2. **Price Cap**: the formula for setting rates during the deferred rebasing period
3. **Incremental Capital Module**: addressing incremental capital investment needs during the deferred rebasing period
4. **Base Rate Adjustments**: adjustments to base rates to recognize Union's accumulated deferred tax credit is now fully amortized and to remove the effect of smoothing of EGD's Customer Information System and customer care forecast costs
5. **Customer Protection Measures**: a new scorecard for ongoing monitoring of performance against service quality indicators for customer service, operations, system reliability and safety
6. **Deferral and Variance Accounts**: a discussion of the deferral and variance accounts during the deferred rebasing period
7. **Annual Adjustment Process**: the annual process to set rates under the Price Cap formula
8. **Stakeholder Meeting**: formal engagement with stakeholders on a biennial basis
9. **Reporting**: utility information to be reported annually
10. **Other Matters**: rate design considerations, changes to accounting practices and approach to prior Board directives and/or commitments

2. PRICE CAP

EGD's 2014-2018 rate setting model (EB-2012-0459) is Custom Incentive Regulation ("Custom IR"), while Union's 2014-2018 IRM (EB-2013-0202) sets rates using a Price Cap. Consistent with the Board's policy for Rate-Making Associated with Distributor Consolidations, following the expiration of the current IR mechanisms, rates for regulated distribution, transmission and storage services over the deferred rebasing period will be based on the Price Cap IR mechanism using a PCI calculated as PCI = I – X ± Y ± Z, where rates are a function of:

- An inflation factor;
- A productivity factor (X factor);
- Certain predetermined pass-through adjustments (Y factors); and
- Certain non-routine adjustments (Z factors).

Unlike the Price Cap IR methodology established by the Board for electricity distributors, the Board has no established industry-specific inflation and productivity factors for natural gas distributors. The Applicants are proposing to use an economy-wide inflation index consistent with the existing Board-approved Union Price Cap framework and a productivity factor based on Total Factor Productivity Analysis to set rates during the deferred rebasing period.

Each of these components is discussed below.

2.1 INFLATION

The Applicants propose to use the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") Canada index as the inflation factor. The factor will be calculated annually and will be available once Statistics Canada has published its Q2 data, which usually occurs in late August. The annual calculation is the average of the four quarters, ending in June each year. For 2019, the inflation factor will be based on GDP IPI FDD from Q3 2017 to Q2 2018.

Union has used GDP IPI FDD for the inflation factor in its previous Price Cap formulas, and the Board is therefore familiar with its operation. The measure comes from a respected impartial source (Statistics Canada) and therefore eliminates the need to develop and evaluate an alternative approach for inflation. The approach is also consistent with the methodology used to develop the productivity factor.

2.2 PRODUCTIVITY FACTOR

The Applicants propose a productivity factor based on the Total Factor Productivity Analysis and associated recommendations prepared by Jeff Makholm of National Economic Research Associates Inc. ("NERA"), who was engaged by the Applicants. Based on his analysis, Dr. Makholm recommends an X factor of zero and further recommends that a stretch factor would not be appropriate. The NERA report is provided in Exhibit B, Tab 2.

The analysis and evidence provided by NERA finds that an X factor of zero is appropriate. EGD and Union's productivity growth is in line with the economy as whole and the economy-wide inflation is appropriate for setting rates during the deferred rebasing period.

Further, over the deferred rebasing period Amalco expects to experience increasing cost pressures, such as line locates, potential stricter pipeline safety regulations, increased municipal infrastructure activity that impacts natural gas infrastructure (e.g. roads, bridges, etc.) and depreciation increases even when managing maintenance capital expenditures to the level of depreciation. In addition, economists currently believe the Canadian economy will be exposed to increasing interest rates over the next decade. Both EGD and Union have refinanced virtually all of their existing long-term debt based on historically low interest rates that have existed over the past 10 years. Amalco will be required to refinance approximately 50% of its existing long-term debt during the deferred rebasing period. Higher interest rates combined with refinancing a significant portion of existing long-term debt could put significant pressure on Amalco's earnings.

2.3 Y FACTORS

Y factors are costs associated with specific items that are subject to deferral account treatment and passed through to customers and are not subject to escalation. Amalco will treat the following costs as Y factors:

- Cost of gas and upstream transportation;

- Demand Side Management ("DSM") costs as determined in EB-2015-0029/EB-2015-0049 and any subsequent proceeding;
- Lost Revenue Adjustment Mechanism ("LRAM") for the contract market;
- Normalized Average Consumption/Average Use;
- Cap-and-Trade; and
- Capital investments that qualify for Incremental Capital Module treatment, as described in further detail in Section 3.

Cost of Gas and Upstream Transportation

In accordance with current treatment, the cost of gas supply, upstream transportation and gas supply balancing will continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism ("QRAM"), including the prospective disposition of gas supply related deferral accounts. Amalco will continue to follow the Board's guidelines for the QRAM process.

Demand Side Management and Lost Revenue Adjustment Mechanism

In accordance with current treatment, any changes to DSM program costs will be updated in rates and implemented as part of the DSM program review process.

The LRAM will continue to exist for the contract rate classes.

Normalized Average Consumption/Average Use Adjustment

The Applicants are proposing to continue to adjust rates annually to reflect the declining trend in use.

Cap-and-Trade

Costs associated with Cap-and-Trade costs will be filed in future proceedings.

2.4 Z FACTORS

To address material changes in costs associated with unforeseen events outside of the control of management the OEB's Price Cap formula includes a Z factor mechanism.

The Applicants propose to use the criteria defined in the OEB's Filing Requirements for Natural Gas Rate Applications that any Z factor must meet the following criteria to qualify for recovery:

1. Causation – the change in cost, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside of the base upon which rates were derived
2. Materiality – the effect of the change in cost on the utility's revenue requirement in a year must be equal to or greater than the established threshold
3. Prudence – the change in cost must have been prudently incurred
4. Management Control - the cause of the change in cost must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence.

The Applicants propose using a materiality threshold of $1.0 million for Amalco during the deferred rebasing period. This is consistent with the threshold for electric distributors.[7]

Over the deferred rebasing period there is the potential for changes which could impact Amalco that would be outside of the direct control of management. As indicated above, interest rates are poised to increase. If there is a material impact on Amalco's ability to earn its allowed ROE, Amalco may address this through an application to the Board. Another example is government policy changes, including climate policy, which could have a significant impact on Amalco. Amalco will evaluate each situation to determine whether Z factor treatment is appropriate.

3. INCREMENTAL CAPITAL MODULE ("ICM")

During the deferred rebasing period, Amalco will apply for rate adjustments using the OEB's ICM to recover costs associated with qualifying incremental capital investment beyond what is normally funded through approved rates consistent with the Board-established policy on ICM[8]. The Consolidation Handbook provides the ICM option for funding incremental capital investments during the deferred rebasing period. Capital projects related to the amalgamation will be funded and managed by Amalco as an integral part of supporting achievement of synergies through the deferred rebasing period.

---

[7] Filing Requirements for Electricity Distribution Rate Applications July 14, 2016 at Section 2.0.8 (Materiality Thresholds) sets a materiality threshold of $1 million for a distributor with a distribution revenue requirement of more than $200 million.

[8] Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014 and Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016. The ICM Filing Requirements are also documented in the OEB's Filing Requirements for Electricity Distribution Rate Applications.

Qualifying incremental capital investments are discrete projects that satisfy the criteria documented in the OEB reports[9]. One of the qualifying criteria is that the capital investment will cause the total capital budget to exceed the threshold value of capital expenditures that can be funded through approved rates.

The level of capital spend that can be managed under the Price Cap approach is determined by the OEB's calculation of the ICM materiality threshold value.

$$\text{Threshold value (\%)} = 1 + [(RB/d) \times (g + PCI \times (1+g))] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Rate Base	RB	approved rate base from the last cost of service application
Depreciation	d	approved depreciation expense from the last cost of service application
Growth	g	annual growth rate
Price Cap Index	PCI	Price cap index for the most recent Price Cap IR application
Years since rebasing	n	the number of years since the cost of service rebasing

The Applicants have calculated the thresholds for the ICM for EGD and Union using 2018 and 2013 approved rate base and depreciation respectively. The 2019 capital investment threshold calculation for EGD and Union is shown in Table 1.

[9] Ibid.

Table 1
Illustrative ICM Threshold Calculation for 2019 for EGD and Union
($ millions)

	EGD	Union
Base year	2018	2013
Rate base	6,246	3,734
Depreciation	305	196
PCI %	1.73%	1.73%
Growth %	0.93%	0.93%
Years since rebasing	1	6
Threshold value %	165%	168%
Threshold value	503	330

The capital investment required to grow and maintain safe and reliable service to customers on the transmission and distribution systems is supported by EGD's and Union's Asset Management Plans. These plans were generated prior to the proposal to amalgamate the utilities. While there are some differences, each 10 year plan and the associated processes support the long term optimization of asset investments to balance cost, risk, and performance. Management expects to integrate EGD and Union into a single set of asset management processes and software during the deferred rebasing period. It is expected that future Asset Management Plans will benefit from the amalgamation by sharing best practices, and experience as well as the opportunity to optimize investment in administrative facilities, information systems and other general administrative and support assets.

Management anticipates a need for incremental capital investment to reinforce existing pipeline systems where capacity is not available to support future growth and to replace pipeline systems (or portions of systems) where programs to extend the life of the asset are no longer the most cost-effective option. These types of capital investment are beyond what is funded through approved rates without adjustments. Rate adjustments to fund incremental capital investment in the 2014 to 2018 incentive mechanisms are addressed by EGD’s Custom IR and Union’s capital pass-through mechanism. Union’s existing capital pass-through mechanism is consistent with the Board’s ICM.

Amalco proposes to bring forward the Asset Management Plan(s) to provide information to the Board, as required, in the annual rate applications in support of ICM proposals. In the case of a qualifying project that requires a Leave to Construct (“LTC”) application the request for approval of the proposed adjustment to rates will be filed with the LTC. Proposals to adjust rates for investments not subject to LTC will be addressed in the annual rate setting process.

In the annual rate application, the Applicants will be requesting approval of a rate adjustment to fund forecast incremental capital projects that qualify for ICM. In calculating the revenue requirement for the proposed ICM, the methodology applied will be consistent with the Board requirements with one exception.

The Board requires the use of approved cost of capital parameters when calculating the revenue requirement. The Board’s ICM policy was established for five year ratemaking models. Amalco will be operating under a 10 year deferred rebasing period and using a Price Cap. Amalco proposes the cost of capital will reflect the latest forecast cost of debt, incremental long-term debt requirement for the capital project and allowed ROE at the time of the application and be based on the Applicants' current capital structure at 64% debt and 36% equity.

4. BASE RATE ADJUSTMENTS

The Applicants propose to remove two adjustments that were the subject of settlements from prior proceedings and expire at the end of 2018. The first adjustment is an increase to Union's rates for the completion of the Board-approved deferred tax drawdown. The second adjustment is a decrease to EGD's rates for the smoothing of costs related to EGD's Customer Information System ("CIS") and customer care forecast costs. Prior to setting 2019 rates, the first year of the deferred rebasing term, Union and EGD's respective rates will be adjusted for the deferred tax drawdown and the CIS and customer care costs.

4.1 UNION'S DEFERRED TAX DRAWDOWN

The Applicants propose to increase Union's 2018 Board-approved revenue by $17.4[10] million pre-tax ($12.8 million after-tax) to recognize the accumulated deferred tax balance (credit) is now fully amortized. This amount represents the difference between the credit to ratepayers included in 2018 rates, and the accumulated deferred tax balance at the end of 2018 of zero.

[10] $12.819 million / (1-26.5%) = $17.441 million (deferred tax adjustment included in 2018 rates of $12.819 million after-tax divided by 1 minus the tax rate = $17.441 million pre-tax).

History of Deferred Tax Drawdown

In 1997, Union changed its accounting for utility income taxes from the tax allocation (or accrual) method to flow-through (or cash-basis) tax accounting. This change was adopted for rate-making purposes on a prospective basis and approved by the Board in its E.B.R.O. 493/494 Decision. The tax allocation method of accounting used for rate-making purposes prior to E.B.R.O. 493/494 resulted in an accumulated deferred tax balance.

One consequence of moving to flow-through accounting was the need for a transitional measure to address the existing accumulated deferred tax balance. In the E.B.R.O. 499 Board-approved Settlement Agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union's cost of service in future years by virtue of a drawdown mechanism.

The amount of the annual drawdown was based on the "natural" reversal of the timing differences (primarily related to Capital Cost Allowance ("CCA") and depreciation) which originally gave rise to the deferred tax balance. However, during IRM periods, parties agreed to normalize the drawdown to avoid annual rate adjustments. The Board-approved drawdown spanned a period of 20 years, beginning in 1999 and ending in 2018.

The drawdown of the deferred tax balance, starting with Union's last rebasing year (2013), is shown in Table 2 below. Ratepayers have received the benefit of lower rates for the past 20 years due to the drawdown of the deferred tax benefit.

Table 2
Deferred Tax Balance ($000's)

Line No.	Fiscal Year	Opening Balance	Drawdown Utilized (after-tax)	Closing Balance
1	2013	(79,263)	(15,169)	(64,094)
2	2014	(64,094)	(12,819)	(51,275)
3	2015	(38,456)	(12,819)	(38,456)
4	2016	(25,638)	(12,819)	(25,638)
5	2017	(25,638)	(12,819)	(12,819)
6	2018	(12,819)	(12,819)	-

Union's Proposal to Adjust Base Rates

Union proposes to increase 2018 Board-approved revenue by $17.4 million pre-tax since the annual drawdown of the deferred tax balance is completed in 2018. Ratepayers have received the benefit of lower rates for the past 20 years due to the drawdown of the deferred tax benefit. Union proposes the benefit be removed from rates now that the balance is zero and there is no further deferred tax drawdown credit to reduce rates.

4.2 EGD's CIS AND CUSTOMER CARE FORECAST COSTS

The Applicants propose to decrease EGD's 2018 Board-approved revenue by $4.9 million to recognize the approved CIS and customer care cost level of $126.2 million rather than the $131.1 million in 2018 Board-approved rates.

History of CIS and Customer Care Costs

EGD's CIS and Customer Care forecast costs and allowed revenue within rates for the years

2013-2018 were derived under an OEB-approved Settlement Agreement, EB-2011-0226.[11] In the Settlement Agreement, parties agreed that forecast CIS and customer care costs for the six year period would have a smoothing mechanism applied to them for determination of revenue and rate recovery purposes. The original forecast costs and revenues, based on forecast annual levels of customers at the time, were converted into approved cost per customer and smoothed cost per customer (revenue) unit rates. These unit rates were to be used annually, along with annually updated forecast levels of customers, to update the annual approved forecast costs and revenues for each year of the agreement.

The resulting impact of this smoothing mechanism was that in the years 2013-2015 the allowed costs and related cost per customer unit rates would be higher than the allowed revenues and related smoothed cost per customer unit rates recovered in rates, and, in the years 2016-2018 the approved costs and related cost per customer unit rates would be lower than the allowed revenues and related smoothed cost per customer unit rates recovered in rates.

In order to ensure the approved smoothing mechanism did not have any undue impact on earnings and earnings sharing results, parties agreed to establish a deferral account to record the annual difference between approved revenues and costs. The deferral account was not cleared on an annual basis, as over the six year term the account would in essence balance to zero (a

---

[11] EB-2011-0226, EGD Application Re: Approval of Revenue Requirement for CIS and Customer Care Costs from 2013to 2018.

minimal balance will actually exist in the account with required clearance due to the forecast customer amounts being updated annually versus originally forecast).

EGD's Proposal to Adjust Base Rates

The result of the smoothing mechanism is that in 2018 the approved rates will recover revenues of $131.1 million while the approved costs are effectively $126.2 million. EGD will book an entry to credit the deferral account by an amount of $4.9 million such that the income statement recognizes a match between approved revenue and costs.

The approved CIS and customer care cost level for 2018 is $126.2 million (compared to 2018 rates recovering $131.1 million) and therefore, EGD proposes to decrease 2018 rates by $4.9 million. Absent this adjustment, the application of a price cap formula against approved 2018 rates will generate future revenues that would immediately exceed the approved costs in 2018 (i.e. ongoing rates would reflect a timing difference that was specific to the 2013 – 2018 time period).

5. CUSTOMER PROTECTION MEASURES

The Applicants propose a Scorecard to measure and monitor performance over the 10 year deferred rebasing period. The proposed Scorecard is modelled after the electricity distributors' scorecard and includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance. The Scorecard is provided at Exhibit B, Tab 1, Attachment 2. The Scorecard metrics include a combination of existing metrics, service quality requirements ("SQR") and best practice metrics; and aims to align customer and utility interests, while continuing to achieve public policy objectives and reinforcing fiscal prudence. The categories of measures included in the scorecard are as follows:

Customer Focus: This performance measure is focused on service quality and customer satisfaction. The metrics included in this measure are the Board's customer care related SQRs. These include:

1. Reconnection response time
2. Scheduled appointments met on time
3. Telephone calls answered on time
4. Customer complaint written response
5. Billing accuracy
6. Abandon rate
7. Time to reschedule missed appointments

Operational Effectiveness: This performance measure is focused on safety, system reliability and asset management. The metrics included in this measure include the Board's operations related SQRs and metrics for compression reliability and damages:

8. Meter reading performance
9. Percent of emergency calls responded within one hour
10. Compression reliability
11. Damages

Public Policy Responsiveness: This performance measure includes a metric that addresses natural gas savings achieved through DSM programs:

12. Total cumulative cubic meters of natural gas saved[12]

Financial Performance: This performance measure includes metrics that align with the Applicants' current OEB reporting, through the OEB Yearbook that is published annually. These include:

13. Current ratio
14. Debt ratio
15. Debt to equity ratio
16. Interest coverage
17. Financial statement return on assets
18. Financial statement return on equity

The proposed Scorecard will demonstrate Amalco's continued focus on providing safe and reliable service to customers.

6. DEFERRAL AND VARIANCE ACCOUNTS

The list of the Applicants' current approved deferral and variance accounts is provided at Exhibit B, Tab 1, Attachment 3. EGD did not request the continuation of its Customer Care Services

[12] Board-approved, following the completion of the DSM audit process and associated Board process.

Procurement Deferral Account as part of its 2018 Rates Application, EB-2017-0086. Union requested approval to close its Energy East Pipeline Consultation Cost deferral account in its 2018 Rates Application. [13]

The accounts to be continued during the deferred rebasing period are shown at Exhibit B, Tab 1, Attachment 4. Changes to accounting and reporting processes related to deferral and variance accounts as part of the integration activities will be proposed if required during the deferred rebasing period.

The following accounts will be eliminated as a result of the amalgamation, or are related to EGD's Custom IR period from 2014 through 2018.

Account Number	**Account Name**
EGD	
179.16_	Customer Care CIS Rate Smoothing Deferral Account
179.34_	Constant Dollar Net Salvage Adjustment Deferral Account
179.96_	Relocations Mains Variance Account
179.98_	Replacement Mains Variance Account
179.24_	Post-Retirement True-up Variance Account
179.58_	Earnings Sharing Mechanism Deferral Account
Union	
179-120	CGAAP to IFRS Conversion Costs
179-134	Tax Variance Deferral Account

Customer Care CIS Rate Smoothing Deferral Account - In accordance with EGD's Board-approved EB-2011-0226 CIS Customer Care Settlement Agreement, over the 2013 through 2018 period, the Customer Care CIS Rate Smoothing Deferral Account has been used to capture the

[13] EB-2017-0087, Exhibit A, Tab 1, pp. 15-16.

difference between the Board-approved customer care and CIS costs, versus the smoothed amount collected in rates. Following 2018, customer care activities will be subject to integration, the costs of which will be managed under the Price Cap mechanism during the deferred rebasing period.

Constant Dollar Net Salvage Adjustment Deferral Account - EGD has recorded the variance between actual and approved amounts for refund to ratepayers, during the 2014 through 2018 incentive period, related to the reduction in the reserve for net salvage approved by the OEB. A final true-up of this account will occur in 2018, subject to the approval of EGD's Discontinuance of Site Restoration Cost Rider (Rider D) proposal included in its 2018 Rate Application, EB-2017-0086, or the end of 2018, in accordance with the EB-2012-0459 Decision, and will therefore no longer be required.

Relocations Mains Variance Account and Replacement Mains Variance Account - EGD's accounts will not continue at the expiry of the term of the custom incentive regulation period. Costs related to capital expenditures will be managed under the Price Cap through the ICM if required.

Post-Retirement True-up Variance Account - Under EGD's Custom IR mechanism, pension and OPEB related operating and maintenance costs are re-forecast annually and approved to be recovered in rates (EB-2012-0459) subject to deferral of the variance between the forecast and actual costs. Under the Price Cap mechanism rates will not be adjusted for changes in pension and OPEB costs. Pension and OPEB costs will be harmonized and managed by the Amalco.

Earnings Sharing Mechanism Deferral Account - Both utilities have earnings sharing mechanisms as part of their current incentive regulation framework. Union does not have a Board-approved deferral account; the ratepayer portion of any earnings sharing is recorded as a liability. EGD's existing deferral account will be eliminated. Amalco will be subject to earnings sharing beginning in 2024 and will record any earnings sharing amounts as a liability at that time.

CGAAP to IFRS Conversion Costs - Union has recorded the IFRS conversion costs incurred prior to 2013 for recovery from ratepayers. This account was cleared at the end of 2016 and is no longer required.

Tax Variance Deferral Account - Union treats changes in the amount of taxes payable resulting from changes to federal and/or provincial legislation as a Z factor, sharing 50% of the impact with ratepayers (EB-2013-0202). Over the past few years this account has been used to capture variances in HST input tax credits only, as these are the only tax changes to have taken place.

As purchasing and payment processes are integrated, developing processes to continue to capture variances in HST input tax credits related to purchases for Union North and Union South rate classes is unnecessarily complex. This account will be eliminated. Z factor treatment will continue to be available during the deferred rebasing period in the event of significant changes to taxes that are outside of management's control.

7. ANNUAL ADJUSTMENT PROCESS

To set annual rates during the deferred rebasing period, the Applicants propose to file the following information annually:

1. An application for approval of any Z factor adjustments, the pricing of any new regulated services or cost allocation and rate design proposals for which advance approval from the Board is required, in a time frame that would enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates;
2. Along with the application and supporting evidence, a draft rate order for EGD, Union North and Union South rate zones filed by September 30 which reflects the impact of the PCI, Y factors, approved Z factors and normalized average consumption/average use. The documentation would be in sufficient detail to allow the Board to issue a procedural order, such that a final rate order could be issued by December 15 for implementation by January 1;
3. In the event that Amalco requests ICM treatment of projects that will not be examined as part of a LTC application (described in further detail in Section 3), the supporting documentation will be filed earlier than September 30; and
4. As soon as reasonably possible following the public release of annual audited financial statements, Amalco will apply for the disposition of actual year-end non-commodity deferral account balances (including earnings sharing post-2024). The Applicants will use best efforts to file the applications and pursue the regulatory process such that, after the

Board's decision, the Applicants would be able to implement all rate adjustments associated with the deferral account disposition in the earliest possible QRAM. Amalco would continue to adjust gas supply commodity and upstream transportation costs through the QRAM mechanism as approved by the OEB.

8. Stakeholder Meeting

To help ensure a greater understanding and transparency of overall operations during the deferred rebasing term, the Applicants propose to jointly host a funded stakeholder meeting every other year starting in 2019 to:

1. Review the previous years' financial results (e.g. earnings, capital spending) and other key operating parameters (e.g. scorecard performance);
2. Present and explain market conditions and expected changes/trends, and the impact these may have on regulated operations;
3. Present a view of new capital projects that meet the ICM criteria as defined in Section 3;
4. Present an update on the customer engagement activities undertaken and the resulting actions taken in response to customer engagement;
5. Present an update on integration planning and execution; and,
6. Present and review the gas supply plan (subject to the outcomes of the Board's Framework for the Assessment of Distributor Gas Supply Plans, which may specify different timing).

9. REPORTING

To help ensure transparency during the deferred rebasing term, Amalco will prepare utility information for the most recent fiscal year and distribute it annually during the deferred rebasing period. The information largely aligns with the schedules provided during EGD's 2014-2018 Custom IR and Union's 2014-2018 IRM. The schedules are:

1. Calculation of revenue deficiency / (sufficiency);
2. Statement of utility income;
3. Statement of earnings before interest and taxes;
4. Summary of cost of capital;
5. Total weather normalized throughput volume by service type and rate class;
6. Total actual (non-weather normalized) throughput volumes by service type and rate class;
7. Total weather normalized gas sales revenue by service type and rate class;
8. Total actual (non-weather normalized) gas sales revenue by service type and rate class;
9. Delivery revenue by service type and rate class and service class;
10. Total customers by service type and rate class;
11. Summary revenue from regulated storage and transportation;
12. Other revenue;
13. Operating and maintenance expense by cost type (actuals only);
14. Calculation of utility income taxes;
15. Calculation of capital cost allowance;

16. Provision for depreciation, amortization and depletion;
17. Capital budget analysis by function;
18. Statement of utility rate base (actuals only); and
19. Scorecard results.

Further, during the deferred rebasing period, Amalco will continue to develop its customer engagement processes and will ensure that the results of those processes inform Amalco's business plans.

10. OTHER MATTERS

10.1 RATE DESIGN

The Applicants will maintain the existing rate zones (EGD, Union North, and Union South) during the deferred rebasing period. The rate zone of new customers will be defined by the franchise area under which the customer would have been served prior to amalgamation.

For purposes of applying the rate setting mechanism in an annual rate application, Amalco will use approved regulated service offerings, cost allocation methodologies and rate design during the deferred rebasing period. Amalco may propose changes to regulated service offerings, cost allocation and rate design during the deferred rebasing period to address identified issues, make improvements and respond to changing business needs. Any changes to regulated service offerings or approved methodologies will be proposed by Amalco for Board approval as part of the annual rate setting process or as part of a separate application.

10.2 CHANGES TO ACCOUNTING PRACTICES

Amalco will report under USGAAP financial standards. During the deferred rebasing period Amalco expects to change accounting practices and processes as part of the implementation of an integrated accounting system. An example of a change in accounting practices is the calculation of depreciation expense. EGD calculates depreciation expense using a monthly average approach and Union uses the mid-year average approach. Amalco will adopt a common approach. As accounting practices become aligned through the integration of EGD and Union, any changes will continue to be governed by internal Management approvals and ultimately reviewed by external auditors as part of Amalco's annual financial statement certification. Changes in accounting practices resulting in material changes in utility earnings (if any) will be reported to the Board as part of the annual regulatory reporting process.

10.3 RESPONSE TO BOARD DIRECTIVES

Both EGD and Union have received prior Board directives and/or made commitments that were to be addressed in their 2019 rebasing proceedings. Many of the directives and commitments are dependent on a comprehensive review that would occur as part of rebasing. Consistent with Section 10.1, Amalco intends to respond to certain directives and commitments during the deferred rebasing period to address identified issues, make improvements and manage changing business needs. These directives and commitments are described in further detail below. Amalco intends to respond to the balance of the directives and commitments as part of its 2029 rebasing proceeding. A listing is provided in Exhibit B, Tab 1, Attachment 5.

EGD Directives/Commitments

There are no directives or commitments to respond to during the deferred rebasing period.

Union Directives/Commitments

EB-2016-0118: File a Normalized Average Consumption ("NAC") Study

As part of the Settlement Agreement approved by the OEB in the 2015 Disposition of Deferral Account Balances proceeding (EB-2016-0118), Union agreed to file a study assessing the continued appropriateness of its methodology for determining the NAC. Union will continue to review NAC as a part of Amalco. Changes to NAC if appropriate will be considered as part of a future rate proceeding.

EB-2016-0186: Comprehensive Review of the Panhandle and St. Clair System Cost Allocation Methodology

The OEB's Decision in Union's Panhandle Reinforcement Project (EB-2016-0186) deferred consideration of the revised cost allocation methodology until Union's next cost of service or custom IR application. The Board-approved cost allocation methodology causes significant impacts to certain rate classes and in response to concerns raised by customers, Amalco intends to address the cost allocation of the Panhandle System and St. Clair System in its 2019 Rates Application.

ENBRIDGE

Certification of Evidence

The undersigned, the President of Enbridge Gas Distribution Inc., in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in the Application is accurate, consistent and complete.

Jim Sanders, President, Enbridge Gas Distribution Inc.

unionGas
An Enbridge Company

Certification of Evidence

The undersigned, the President of Union Gas Limited, in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in the Application is accurate, consistent and complete.

Steve Baker, President, Union Gas Limited

AMALCO OEB SCORECARD

#	Performance Measure	Target
	CUSTOMER FOCUS	
1	Reconnection Response Time (# of days to reconnect a customer) (# of reconnections completed within 2 business days/# of reconnections completed)	OEB: 85% (within 2 days)
2	Scheduled appointments met on time (appointments met within designated time period) (# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month)	OEB: 85%
3	Telephone calls answered on time (call answering service level) (# of calls answered within 30 seconds / # of calls received)	OEB: 75% annually with a minimum of 40% in any given month
4	Customer Complaint Written Response (# of days to provide a written response) # of complaints requiring response within 10 days / # of complaints requiring a written response	OEB: 80% (within 10 days)
5	Billing accuracy Number of manual checks done as per quality assurance program, for excessively high or low usage.	
6	Abandon Rate (# of calls abandon rate) (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	OEB: <10%
7	Time to Reschedule Missed Appointments (% of rescheduled work within 2 hours of the end of the original appointment time)	OEB: 100%
	OPERATIONAL EFFECTIVENESS	
8	Meter Reading Performance # of meters with no read for 4 consecutive months / # of active meters to be read	OEB: <0.5%
9	% of Emergency Calls Responded within One Hour (# of emergency calls responded within 60 minutes / # of emergency calls)	OEB: 90% Target
10	Compression Reliability % reliable for transmission compression	
11	Damages Third party line breaks per 1,000 locate requests	
	PUBLIC POLICY RESPONSIVENESS	
12	Total Cumulative Cubic Meters of Natural Gas Saved*	
	FINANCIAL PERFORMANCE	
13	Current Ratio (current assets / current liabilities)	
14	Debt Ratio (total debt / total assets)	
15	Debt to Equity Ratio (total debt / shareholders' equity)	
16	Interest Coverage (EBIT / interest charges)	
17	Financial Statement Return on Assets (net income / total assets)	
18	Financial Statement Return on Equity (net income / shareholders' equity)	

*Board-approved, following the completion of the DSM audit process and associated Board process

EGD and Union: List of Existing Deferral Accounts

EGD

Acct #	Acct Name
179.00_	Deferred Rebate Account
179.02_	Transition Impact of Accounting Change Deferral Account
179.04_	Demand Side Management Cost-efficiency Incentive Deferral Account
179.06_	Demand Side Management Variance Account
179.08_	Ex-franchise Third Party Billing Services Deferral Account
179.10_	Lost Revenue Adjustment Mechanism
179.16_	Customer Care CIS Rate Smoothing Deferral Account
179.18_	Customer Care Services Procurement Deferral Account
179.20_	Gas Distribution Access Rule Impact Deferral Account
179.24_	Post-Retirement True-up Variance Account
179.26_	Demand Side Management Incentive Deferral Account
179.30_	Manufactured Gas Plant Deferral Account
179.32_	Greenhouse Gas Emissions Impact Deferral Account
179.34_	Constant Dollar Net Salvage Adjustment Deferral Account
179.36_	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account
179.40_	Dawn Access Costs Deferral Account
179.48_	Open Bill Revenue Variance Account
179.58_	Earnings Sharing Mechanism Deferral Account
179.60_	Electric Program Earnings Sharing Deferral Account
179.66_	Average use True-up Variance Account
179.70_	Purchased Gas Variance Account
179.80_	Transactional Services Deferral Account
179.82_	Greenhouse Gas Emissions Compliance Obligation - Customer Related Variance Account
179.84_	Greenhouse Gas Emissions Compliance Obligation - Facility Related Variance Account
179.86_	Unaccounted for Gas Variance Account
179.88_	Storage & Transportation Deferral Account
179.94_	OEB Cost Assessment Variance Account
179.96_	Relocations Mains Variance Account
179.98_	Replacement Mains Variance Account

Union

179-070	Short-term Storage and Other Balancing Services
179-075	Lost Revenue Adjustment Mechanism
179-100	Transportation Tolls and Fuel - Northern and Eastern Operations Area
179-103	Unbundled Services Unauthorized Storage Overrun
179-105	North Purchase Gas Variance Account
179-106	South Purchase Gas Variance Account
179-107	Spot Gas Variance Account
179-108	Unabsorbed Demand Cost (UDC) Variance Account
179-109	Inventory Revaluation Account
179-111	Demand Side Management Variance Account
179-112	Gas Distribution Access Rule (GDAR) Costs
179-120	CGAAP to IFRS Conversion Costs
179-123	Conservation Demand Management
179-126	Demand Side Management Incentive
179-131	Upstream Transportation Optimization
179-132	Deferral Clearing Variance Account
179-133	Normalized Average Consumption (NAC) Account
179-134	Tax Variance Deferral Account
179-135	Unaccounted for Gas (UFG) Volume Variance Account
179-136	Parkway West Project Costs
179-137	Brantford-Kirkwall/Parkway D Project Costs
179-138	Parkway Obligation Rate Variance
179-139	Energy East Pipeline Consultation Costs
179-141	Unaccounted for Gas (UFG) Price Variance Account
179-142	Lobo C Compressor/Hamilton to Milton Pipeline Project Costs
179-143	Unauthorized Overrun Non-Compliance Account
179-144	Dawn H/LoboD/Bright C Compressor Project Costs
179-145	Transportation Tolls and Fuel – Union North West Operations Area
179-146	Transportation Tolls and Fuel – Union North East Operations Area
179-147	Union North West Purchase Gas Variance Account
179-148	Union North East Purchase Gas Variance Account
179-149	Burlington Oakville Project Costs
179-150	DSM Cost-Efficiency Incentive Deferral Account
179-151	OEB Cost Assessment Variance Account
179-152	Greenhouse Gas Emissions Impact Deferral Account
179-153	Base Service North T-Service TransCanada Capacity Deferral Account
179-154	Greenhouse Gas Emissions Compliance Obligation - Customer-Related
179-155	Greenhouse Gas Emissions Compliance Obligation - Facility-Related
179-156	Panhandle Reinforcement Project Costs

Amalco: List of Deferral Accounts to be Continued During Deferred Rebasing Period

Acct #	Acct Name
179.00_	Deferred Rebate Account
179.02_	Transition Impact of Accounting Change Deferral Account
179.04_	Demand Side Management Cost-efficiency Incentive Deferral Account
179.06_	Demand Side Management Variance Account
179.08_	Ex-franchise Third Party Billing Services Deferral Account
179.10_	Lost Revenue Adjustment Mechanism
179.20_	Gas Distribution Access Rule Impact Deferral Account
179.26_	Demand Side Management Incentive Deferral Account
179.30_	Manufactured Gas Plant Deferral Account
179.32_	Greenhouse Gas Emissions Impact Deferral Account
179.36_	Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account
179.40_	Dawn Access Costs Deferral Account
179.48_	Open Bill Revenue Variance Account
179.60_	Electric Program Earnings Sharing Deferral Account
179.66_	Average use True-up Variance Account
179.70_	Purchased Gas Variance Account
179.80_	Transactional Services Deferral Account
179.82_	Greenhouse Gas Emissions Compliance Obligation - Customer Related Variance Account
179.84_	Greenhouse Gas Emissions Compliance Obligation - Facility Related Variance Account
179.86_	Unaccounted for Gas Variance Account
179.88_	Storage & Transportation Deferral Account
179.94_	OEB Cost Assessment Variance Account
179-070	Short-term Storage and Other Balancing Services
179-075	Lost Revenue Adjustment Mechanism
179-100	Transportation Tolls and Fuel - Northern and Eastern Operations Area
179-103	Unbundled Services Unauthorized Storage Overrun
179-105	North Purchase Gas Variance Account
179-106	South Purchase Gas Variance Account
179-107	Spot Gas Variance Account
179-108	Unabsorbed Demand Cost (UDC) Variance Account
179-109	Inventory Revaluation Account
179-111	Demand Side Management Variance Account
179-112	Gas Distribution Access Rule (GDAR) Costs
179-123	Conservation Demand Management
179-126	Demand Side Management Incentive
179-131	Upstream Transportation Optimization
179-132	Deferral Clearing Variance Account
179-133	Normalized Average Consumption (NAC) Account
179-135	Unaccounted for Gas (UFG) Volume Variance Account
179-136	Parkway West Project Costs
179-137	Brantford-Kirkwall/Parkway D Project Costs
179-138	Parkway Obligation Rate Variance
179-141	Unaccounted for Gas (UFG) Price Variance Account
179-142	Lobo C Compressor/Hamilton to Milton Pipeline Project Costs
179-143	Unauthorized Overrun Non-Compliance Account
179-144	Dawn H/LoboD/Bright C Compressor Project Costs
179-145	Transportation Tolls and Fuel – Union North West Operations Area

179-146	Transportation Tolls and Fuel – Union North East Operations Area
179-147	Union North West Purchase Gas Variance Account
179-148	Union North East Purchase Gas Variance Account
179-149	Burlington Oakville Pipeline Project
179-150	DSM Cost-Efficiency Incentive Deferral Account
179-151	OEB Cost Assessment Variance Account
179-152	Greenhouse Gas Emissions Impact Deferral Account
179-153	Base Service North T-Service TransCanada Capacity Deferral Account
179-154	Greenhouse Gas Emissions Compliance Obligation - Customer-Related
179-155	Greenhouse Gas Emissions Compliance Obligation - Facility-Related
179-156	Panhandle Reinforcement Project Costs

EGD and Union OEB Directives / Commitments

The following are Directives of the OEB and or Commitments made by EGD and Union, expected to be addressed when Amalco rebases in 2029.

EGD

1. 2014-2018 CIR Decision Directives
   a. Commitment to develop a benchmarking study attempting to address both capital & operating costs and hold consultation with stakeholders. OEB expects benchmarking work to be supported by independent expert opinion to be filed upon rebasing.
   b. Should undertake a consultation process for SEIM (sustainable efficiency incentive mechanism) proposal/process and devise a revised proposal to bring forward in 2015 or 2016 rate application. If process does not reach an agreed upon proposal, EGD can proceed to request a revised approach and review at its next rebasing.
   c. Discount rate used to determine SRC provision should be examined in more detail at next rebasing.
   d. OEB directive to examine issue of whether a segregated fund (SRC) should be established as a means of protecting ratepayers – EGD to present such evidence as part of first application following this Custom IR

Union

1. EB-2011-0210 Union's 2013 Cost of Service Proceeding
    a. Union was directed to undertake a comprehensive cost allocation study which includes the M1/M2 and R01/R10 breakpoint reduction proposal no later than Union's 2014 rates filing. The study is to include an analysis regarding the allocation of costs for Distribution Maintenance –Meter and Regulator Repairs related to the customers that would be moving rate classes.

    In the 2014 rates Settlement Agreement (EB-2013-0365), parties agreed that they will jointly retain an independent consultant to conduct a study of the cost allocation and rate design associated with the Rate 01/Rate 10 and Rate M1/Rate M2 general service rate classes. Parties agreed this study would be filed no later than the 2016 rates application. In the 2016 rates evidence (EB-2015-0116) Union filed the volume breakpoint study and committed to review the volume breakpoints and load factor results as part of the 2019 rebasing proceeding.

    b. Union was directed by the Board to file sufficient evidence to support the proposed allocation of Union North and Union South Distribution Maintenance - Equipment on Customer Premises costs to rate classes in proportion to the allocation of customer station gross plant, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520 as part of Union's 2014 rates filing.

    In the 2014 rates application (EB-2013-0365) Union deferred the response to this directive to the 2019 rebasing proceeding.

2. EB-2013-0202 Union's 2014 to 2018 Incentive Regulation Mechanism Settlement Agreement
    a. Union agreed (subject to any subsequent agreement of all parties to extend the IRM term) to prepare a full cost-of-service filing at the time of rebasing, regardless of

whether Union applies to set rates for 2019 on a cost-of-service basis or not.

3. EB-2014-0012 Hagar Liquefaction Service Rate
    a. In its Hagar Liquefaction Service Rate Decision, the OEB directed Union to file a more robust and comprehensive cost allocation study that appropriately allocates costs for the new service in the 2019 rebasing application.

4. EB-2014-0261 Dawn Parkway 2016 Expansion Project Settlement Agreement
    a. Parties agreed that the issue of Dawn Parkway capacity turnback post-2018 and how turnback risk should be dealt with in the context of the proposed facilities would be dealt with in Union's next cost of service proceeding.

5. EB-2016-0186 Panhandle Reinforcement Project
    a. The OEB's Decision in Union's Panhandle Reinforcement Project (EB-2016-0186) deferred consideration of the proposed 20-year depreciation period until Union's next cost of service or custom IR application.

6. EB-2016-0245 Union's 2017 Rates Application Settlement Agreement
    a. Union agreed to report on the revenue neutrality of the new Customer Managed Service (CMS) and revisit the appropriateness of the service design at the time of its rebasing proceeding.

IN THE MATTER OF

EB-2017-0307

Expert Report and Direct Testimony

PREPARED BY

JEFF D. MAKHOLM, PH.D.

NATIONAL ECONOMIC RESEARCH ASSOCIATES INC
200 CLARENDON STREET
BOSTON, MA 02116
USA

ON BEHALF OF

Enbridge Gas Distribution and Union Gas Limited

November 23, 2017

Contents

I. Qualifications and Findings

Q1. Please state your name, business address and current position.

A1. My name is Jeff D. Makholm. I am a Senior Vice President/Managing Director at National Economic Research Associates, Inc. (“NERA”). NERA is a firm of consulting economists with offices in a number of cities in North America and around the world. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q2. Please describe your academic background.

A2. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin-Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. My 1986 Ph.D. dissertation is entitled “Sources of Total Factor Productivity in the Electric Utility Industry.” I also have B.A. and M.A. degrees in economics from the University of Wisconsin-Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q3. Please describe your work experience pertinent to this proceeding.

A3. My work involves pricing, regulation and market issues for regulated infrastructure industries, including natural gas, electricity, water and telecommunications utilities, natural gas and oil pipelines, airports, toll roads and passenger and freight railroads. More specifically, I have consulted for firms, governments, regulatory agencies or interest groups on the issues of competition, rate/toll design, cost of capital, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. As shown in Exhibit JDM-1, my Curriculum Vitae, I have appeared as an expert witness in public utility rate cases and have testified before administrative and civil law courts on more than 250 occasions.

I have directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs/tolls, recommended financing options for major capital projects, advised on industry restructurings, and assisted in the privatization of state-owned gas utilities.

Q4. What is your experience in performing Total Factor Productivity (TFP) growth studies that lead to an independent recommendation of the *X-factor*?

A4. I have been involved in the study and application of TFP growth studies for regulated industries for more than three decades. For my Doctoral work in the 1980s, I performed the first scholarly investigation into the measurement and econometric investigation of the sources of energy utility TFP growth—the model for empirical TFP growth research and application for PBR plans around the world. I have performed TFP growth studies used to set regulated tariffs for energy utilities in Canada, the United States, New Zealand, Mexico, and Argentina.

In 1999, I was involved in Ontario's first investigation of performance-based regulation. Responding to a request for proposal, I directed a project for Ontario Hydro Services Company (OHSC) in 1999 regarding the transition from cost-of-service regulation to the OEB's newly designed PBR framework. OHSC at the time was looking for advice and assistance from an experienced party in developing and supporting its transmission and distribution PBR applications for the next rate order period starting in 2001.

Most recently, I was retained as an independent expert by the Alberta Utilities Commission (the AUC) in its 2011-2012 generic "Rate Regulation Initiative" to identify common regulatory practices or industry standards, compare key provisions in plans proposed by the utilities in Alberta against industry standards, deal with areas where a common standard exists, and analyse the pros and cons of all plans (whether proposed by the utilities or supported by industry standards generally). Working independently, I directed the preparation of a TFP growth study to use for Alberta's electricity and gas distribution companies. The conclusions in that study were accepted by the AUC, in its Decision 2012-237, on all major conclusions of that PBR initiative (methods, data, transparency, output measure, time periods and possible advanced statistical methods). The AUC also adopted my "capital tracker" proposal to ensure the collection of necessary capital expenditures not covered by other elements of an incentive regulation plan. Subsequently, I provided testimony for ATCO Gas in 2013 before the AUC on the implementation of that company's capital tracker mechanism.

Q5. What is your experience with Canadian regulation generally?

A5. I have provided evidence a number of times before federal and provincial regulatory boards in Canada. I presented testimony before the National Energy Board (NEB) on behalf of FortisBC Energy Inc. with respect to the proposals of NOVA Gas Transmission Ltd. to construct the proposed "Komie North," "North Montney," and "Towerbirch" facilities into the shale gas fields of northeast British Columbia (Hearing Orders GH-001-2012, GH-001-2014, and GH-003-2015, respectively). In those proceedings, I focused on three issues: the economic feasibility of the proposed facilities, the potential commercial impacts of the proposed projects, and the appropriateness of the proposed NGTL toll treatment.

I also appeared before the NEB in three cases regarding TransCanada Pipelines on behalf of the Market Area Shippers (MAS). For the MAS Group—a group comprising Enbridge Gas Distribution, Inc., Union Gas Limited, and Société en commandite Gaz Métro—I was involved in the following proceedings: Hearing Orders RH-003-2011 (restructuring); RH-001-2013 (proposed toll amendments); and RH-001-2014 (toll settlement). I also appeared before the NEB on behalf of Enbridge and Union with regard to TransCanada's abandonment cost methodology (MH-001-2013).

In 2010, I was retained by Hydro-Québec TransEnergie ("HQT") to give evidence before the Régie de l'énergie in Québec on the application of traditional regulatory principles to HQT's cost allocation practices and electricity transmission rates. In 2015, on behalf of Société en commandite Gaz Métro, I provided evidence before the Régie de l'énergie regarding the approval and pricing of transmission system capacity additions on the company's Saguenay and the Eastern Township networks.

In 2014, I served as an expert witness for Alliance Pipeline Ltd. in its application to the NEB for approval of New Services and Related Tolls and Tariffs (RH-002-2014). My analysis comprised a review of the proposed tolling methodology and a study to examine market power in Alliance's origin and destination markets.

Q6. In addition to the above, have you published articles or written papers on issues related to the regulation and economics of public utilities—including the measurement of productivity and efficiency in regulated firms?

A6. Yes. Listed on my Curriculum Vitae (attached as Exhibit JDM-1) are many published (or forthcoming) articles, working papers and two books pertaining to economic and regulatory issues associated with natural gas and oil pipelines around the world. Included in those papers is a recent publication (October 2017, *Natural Gas and Electricity*), entitled "Regulating Utility Efficiency 'Fast and Slow': The Current Australian Problem" that comments on the noteworthy problems that Australia is having assessing efficiency in the regulation of electricity distributors there.

Q7. What is the purpose of your testimony in this proceeding?

A7. I have been asked by Enbridge Gas Distribution (EGD) and Union Gas Ltd (Union) to provide testimony in support of the productivity offset (the *X-factor*) to be used in the price cap formula that will apply to its distribution business in the upcoming deferred rebasing periods for each company. I provide independent TFP growth studies for EGD and Union to use with those companies' next incentive regulation application before the Ontario Energy Board (OEB).

Q8. How do you approach the calculation of a productivity offset?

A8. I use a TFP growth analysis to determine empirically the magnitude of the *X-factor* as part of the *RPI-X* regulatory model. I employ data from the US FERC Form 1 and data from EGD and Union to derive the TFP growth for the companies' distribution services.

Q9. What do you conclude from your analysis?

A9. I recommend, on the basis of my customary empirical analysis in such cases, that EGD and Union should be subject to a zero *X-factor* with a zero "stretch factor." Throughout my testimony, I will explain the basis for my recommendations.

Q10. How do you organize your testimony?

A10. My testimony has five sections to follow. In **Section II**, I provide a brief re-cap of the source of *RPI-X* regulation and the essential, intuitive role played by the *X-factor* in that model of regulation. In **Section III**, I present the theoretical model that describes what the *X-factor* is meant to measure as it serves to mimic a competitive pricing constraint over defined rate formula periods for regulated firms. In **Section IV**, I describe the empirical methods for measuring the various inputs and outputs called for by that theory. In **Section V**, I present my TFP computations for EGD, Union and the US energy distribution companies covered by the Form 1 data that served as the basis for my recommendations that were accepted by the AUC in its Rate Regulation Initiative in 2012, updated to include data through 2016. In **Section VI**, I present my conclusions.

II. Economic Intuition Behind the *X-factor*

Q11. What is the purpose of this part of your testimony?

A11. I describe, with references to the literature on the subject, what the *X-factor* is for, including if and when it requires adjustment by means of a "stretch" factor.

Q12. Where does the *X-factor* come from?

A12. The basic *RPI-X* price cap incentive regulation model is a UK import, implemented there to speed that country's rapid privatization under the Margaret Thatcher government in the 1980s. Its allure to the UK government lay in its promise both to bypass the perceived inefficiencies of, what was described there as, "cost plus" regulation in North America (an unfortunately simplistic label in my opinion) and to avoid what it also perceived to be various difficult regulatory institutions and procedures—the creation of which would necessarily slow down quick privatization (which is what the Thatcher government demanded).[1] The 1980s also was a time to reassess the longstanding regulatory model in North America, given changes in the telecom market (because of the mandated 1982 breakup of AT&T that produced the regional Bell operating companies) and the evident problems of rising electricity and gas rates.[2] As a result, *RPI-X* regulation attracted considerable scholarly interest.[3] It came to North America first in the regulation of those

[1] As an example of the press for rapid privatization (regarding British Gas), see Makholm, *The Political Economy of Pipelines*, University of Chicago Press, Chicago and London (2012), pp. 57-58.
[2] Makholm, "Electricity Deregulation under Siege," Natural Gas and Electricity, Volume 34, No. 5 (August 2017), p. 29.
[3] Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom, *The Rand Journal of Economics*, Vol. 20,No. 3 (1989), p. 457.

regional Bell operating companies—and then to a few US electricity and gas companies in a small number of states (e.g., California, Maine, New York and Massachusetts). It also attracted attention in Ontario, British Columbia and Alberta.

In US telecommunications, *RPI-X* regulation of local services in the 1990s was a bridge to deregulation and is generally no longer applied in that industry. In US energy regulation, *RPI-X* regulation with a specific *X-factor* did not spread outside the few states that originally pursued it. In Canada, Alberta initiated a generic *RPI-X* "Rate Regulation Initiative" in 2010-2012 with a major emphasis on an empirically-derived *X-factor*, now in its second generation.[4] Ontario is on its fourth generation plan—all of which have referred to an empirically-derived *X-factor*.

Q13. What are the institutions underlying *X-factors*?

A13. *RPI-X* was supposed to be a more efficient alternative than North American utility regulation—permitting rates to rise at a government index of inflation minus an unspecified adjustment factor, called "*X*." As originally conceived in 1983 by its author, Stephen Littlechild, *X* would be part of a "package of measures" in the license responsibilities offered as the UK's public enterprises would be offered to investors through privatization.[5] As such, the government had wide freedom in setting *X*, and Littlechild offered no guide for how to do so. For resetting *X*, or in cases where the package of measures had already been determined, Littlechild admits "there are thus fewer degrees of freedom in resetting *X*," but provides no other guide for its determination.[6] Indeed, where he described the re-setting of *X* in the UK at all, Littlechild emphasizes the broad peremptory powers of regulators that do not translate to Canada or the United States.[7]

---

4 NERA was retained as an independent expert by the Alberta Utilities Commission (AUC) to present the procedures and data for the purpose of computing the *X-factor*. The AUC adopted NERA's methods in their entirety. See AUC, Decision 2012-237, September 12, 2012.

5 Littlechild, S.C., "Regulation of British Telecommunications' Profitability, London: Department of Industry, (1983).

6 Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom, The Rand Journal of Economics, Vol. 20, No. 3 (1989), p. 457.

7 "…in setting *X* the U.K. regulator has more discretion and less need to reveal the basis of his decisions than does his U.S. counterpart. … In the U.K., there is less pressure for due process, [and] neither governments nor regulators have given detailed reasons for their decisions on *X*." Littlechild (1989), p. 461.

As originally conceived and written about in the UK, *RPI-X* did not deal with any deeper institutions such as administrative procedures, uniform systems of accounting, or the prudence standard involved in the regulation of investor-owned utilities—institutions important to Canadian and US regulation that the UK did not have.[8] Partly for those institutional reasons and partly because of the political nature of UK regulation generally, the implementation of *RPI-X* turned out to be much more difficult and contentious than anticipated. After a notable retrospective on its perceived failures, the UK abandoned that form of regulation in favor of another regulatory model labelled "RIIO" (Revenue = Incentives + Innovation + Outputs).[9]

Q14. How did such regulation translate to North America?

A14. North American regulation has a deep and longstanding institutional foundation inherent in accounting regulation, the "prudence standard," and the *Northwestern Utilities* and *Hope* cases geared toward safeguarding private property in regulated industries.[10] Where *RPI-X* regulation initially resonated best in North America, given such institutions, was in the application to regulated local and interstate telecom companies in the wake of their divestiture from AT&T. The regulated telecom industry could readily define "baskets" of disparate services (which could be subject to the single weighted-average price cap). The industry also was in a period of rapid productivity growth due to new technologies (e.g., electronic switches, digitization, fiber optics). Thus, *RPI-X* regulation gave telecom regulators tools to lighten regulatory burdens both by specifying average price caps and permitting regulated prices to move after being set—taking away the need to persistently update individual regulated service rates.[11] *RPI-X* regulation was a reasonably successful part of the transition to deregulation of that industry.[12]

---

8 See Makholm (2015) for a description of the institutional differences between UK and US utility regulation, and Makholm (2008) for a similar description of the institutional similarities between US and Canadian regulatory institutions.

9 See Makholm (2015). Also see: https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf.

10 *Northwestern Utilities v. City of Edmonton, S.C.R. 186 (NUL 1929)* and *Federal Power Commission et al v. Hope Natural Gas Co*, 320 U.S. 591 (1944).

11 The Federal Communications Commission (FCC) issued a price cap order with an *X-factor* in 1989 (See: FCC 95-132, CC Docket No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," Appendix D). California issued a price cap decision in 1989 (decision D.89-10-031). Massachusetts issue a price cap decision in 1995 (New Eng. Tel. & Tel. Co. dba NYNEX, D.P.U. 94-50, May 12, 1995). NERA assisted with all three efforts.

12 There was a lot more to the deregulation of the telecommunications industry—involving great economic and regulatory controversies. My late NERA colleague Alfred Kahn wrote about those controversies at length. See: Kahn, A.E., *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness*, MSU Public Utility Papers, Michigan State University, East Lansing (1998).

RPI-X regulation did not resonate as well for electric and gas distribution utilities. Companies with a single product (i.e., distribution services) had no telecom-like "basket" of diverse services, no telecom-like rapid technological progress and no prospect of deregulation. Thus, *RPI-X* regulation for energy distribution utilities in North America generally came to be seen as less of an alternative to cost-based regulation (as originally conceived in the UK) than a means to lengthen "regulatory lag" for pricing services that were never foreseen as candidates for deregulation. The AUC echoed such a conclusion in Alberta's generic 2012 "Rate Regulation Initiative" proceeding:

> As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[13]

Q15. Why is an *X-factor* necessary in a price cap model?

A15. Before I answer your question, let me say something about what I call the UK "*X*" as opposed to the North American "*X-factor*."

When I refer to the *X* in Littlechild's *RPI-X* formula, it is just "*X*"—something for the regulator to choose without any need for quantitative justification. North American regulators do not generally have such powers to act without some due process trail—they need some sort of evidentiary support that fits in with the general boundaries on their discretion designed to safeguard investor property (i.e., the *Northwestern Utilities* case). That is, North American regulators cannot simply pull *X* out of the air as their UK colleagues have done. They need evidence: an empirically-derived "*X-factor*" relating to an acceptable theoretical foundation.

Consistent with more longstanding, due process based regulatory institutions designed to produce evidence-based (and hence legally defensible) results, the derivation of the *X-factor* in Canada and the United States moved away from the UK regulatory choice model described originally by Littlechild and into a productivity measurement model designed to mimic a competitive constraint. The measurement of TFP mirrored

[13] AUC Decision 2012-237, page 58 (quoting Exhibit 391.02, NERA second report, paragraph 2).

theoretical advances in the construction of theoretically suitable index numbers coming out of scholarly study on industrial productivity at the University of California-Berkeley and the University of Wisconsin, Madison, including my own work.[14] With such techniques for reliably constructing productivity indexes, the *X-factor* became a regular part of *RPI-X* cases in most of the jurisdictions in Canada and the United States that continue to pursue such a regulatory model.

Q16. But why is an *X-factor* even necessary?

A16. The answer is that the regulatory lag that drives the company incentives, in such incentive-based regulation, requires some sort of allowance for inflation. But the available economy-wide published inflation indexes do not necessarily capture the inflation that is relevant *for the specific regulated business in question*. The *X-factor* comprises those adjustments that *may be required* to permit published inflation indexes to work for a price adjustment formula as applied to a particular regulated company. That is all the *X-factor* does in its application to North American energy utilities: square published inflation indexes to the output price trends of the regulated business in question.

Whether an *X-factor* may be required is an empirical matter. If the utility in question is part of an industry that is growing in productivity in line with the economy as a whole (suitably measured) and faces the same kind of input cost inflation as other firms in the economy (again, suitably measured), then the use of published economy-wide inflation indexes will work—we do not need an *X-factor*. But if the growth in productivity for the industry in question is *different* than the economy's, or input cost inflation for the utility is *different* from that for the economy's businesses generally, then the published economy-wide inflation index will not work to track fairly the inflation to be applied as the cap for the utility's prices.

For example, telecom companies just prior to deregulation displayed considerably greater measured productivity growth than the economy at large—defined as the way they produced their products for the costs they incurred. As such, a price cap plan that used economy wide inflation would not reasonably track regulated telecom prices driven down

[14] See: Makholm. J.D., *Sources of Total Factor Productivity in the Electric Utility Industry*, Unpublished Ph.D. Dissertation, University of Wisconsin-Madison, 1986.

by the industry's greater relative productivity growth. An *X-factor*, drawing on measured productivity in the telecom industry vis-à-vis the economy, would reflect the telecom industry's greater relative productivity growth. The *X-factors* in telecommunications price cap plans at that time tended to be in the 2-5 percent range.[15]

With respect to the sign of the *X-factor* as part of a price cap index for a defined regulatory period, the following is a reasonable summary:

- A positive *X-factor* indicates expected *lower input cost growth* or *higher productivity growth* for the regulated enterprise, vis-à-vis the economy as a whole, which means that economy-wide inflation indexes would overstate the regulated firm's price inflation during the rate formula period.
- A zero *X-factor* means that the economy-wide inflation index is expected to fairly track the regulated firm's price inflation during the rate formula period.
- A negative *X-factor* means that the economy-wide inflation index is expected to be insufficiently large for the purpose of tracking the regulated firm's price inflation during the rate formula period.

Q17. Can an RPI-X performance-based regulatory plan work without a positive *X-factor*?

A17. Yes, of course it can. The *X-factor* is there only to square the deemed inflation index to the relative input growth and TFP growth of the company in question. Whether the result of that squaring is positive or negative has no effect on the incentives provided by such a regulatory regime.

Q18. How has the OEB conducted performance-based regulation for electric distributors?

A18. The Board described the purpose of implementing its first generation of PBR for Ontario's electric distributors as a means to shift away from historical cost of service regulation to a rate mechanism that "provides the utilities with incentive for behavior

[15] See: FCC 95-132, CC Docket No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," Appendix D.

which most closely resembles that of competitive, cost-minimizing, profit-maximizing companies."[16]

As I understand it, the OEB implemented its first generation PBR plans for electric and gas distributors in the time period between 2000 and 2003, depending on the utility.[17] For electric distributors, the OEB's price cap mechanism utilized an industry-specific inflation measure and a productivity measure of 1.5 percent inclusive of a 0.25 percent stretch factor.[18] The Board's second generation plan for electric distributors in the 2007-2009 period was to be a "transitional mechanism" while the Board determined a "formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers."[19] It is my understanding that all electric distributors would be subject to a price cap form of rate adjustment using GDP-IPI FDD and a fixed one percent *X-factor* for the three-year term without a stretch factor.[20]

In the third generation PBR plans for electric distributors, I understand that the OEB decided to retain GDP-IPI FDD as the inflation factor and an input price differential of zero.[21] The Board concluded 0.72 as the appropriate TFP growth value for this third generation IR plan, meaning that it found those electric distributors productivity growth higher than the rest of the economy, and grouped distributors using a benchmarking exercise to assign stretch factors.[22] In the next generation, I understand that the Board identified three options for the price cap adjustment mechanism, as a way to address differing capital investment requirements: 4th Generation Incentive Rate-setting ("4th Generation IR"), Custom Incentive Rate-setting ("Custom IR"), and Annual Incentive

[16] Ontario Energy Board, Decision with Reasons RP-1999-0034.
[17] Ontario Energy Board, Decision with Reasons in RP-1999-0034, Decision with Reasons in RP-1999-0017, and RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005.
[18] Ontario Energy Board, Decision with Reasons RP-1999-0034, pp. 35-41.
[19] Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006., p.23
[20] GDP-IPI FDD stands for Gross Domestic Product Input Price Index Final Domestic Demand. Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 26-33.
[21] Ontario Energy Board, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, p. 11.
[22] Ontario Energy Board, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008, pp. 12, 22.

Rate-setting Index ("Annual IR").[23] The Board adjusted the stretch factor component of the *X-factor* as described in the third generation to evaluate distributors based on total cost benchmarking. I also understand that the OEB adopted a two-factor input price index using 70 % GDP-IPI FDD and 30% change in average weekly earnings ("AWE").[24]

Q19. What is the "stretch factor"?

A19. The AUC, in its 2010-2012 "Rate Regulation Initiative," dealt with the concept of the stretch factor in a comprehensive fashion as part of its new initiative.[25] The AUC made three important determinations regarding the stretch factor that I conclude are reasonable: (1) it does not have a "definitive analytical source" like a TFP growth study, but relies on a regulators' judgment and regulatory precedent; (2) it has no influence by itself on the incentives for regulated companies to reduce costs; and (3) it serves to reflect the "immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."[26]

Most of the parties in the AUC's proceeding, through the various witnesses, as cited by the AUC in its decision, agreed with these opinions of the AUC. To the extent there was disagreement, it focused mostly on whether there was a strong enough change in incentives under the new AUC's PBR regime to warrant a stretch factor. One witness, Dr. Charles J. Cicchetti, noted that the OEB has used a sliding scale of stretch factors for its third-generation PBR regime applied to its electricity distributors for perceived absolute measures of efficiency (as opposed to productivity growth differences that inform TFP growth studies).[27]

The consensus among a broad cross-section of economists, as reflected by the AUC's discussion in that case, is that the foundation for the stretch factor lies in the *transition* to a PBR regime and away from cost-of-service regulation. When historical productivity

[23] Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012.

[24] Ontario Energy Board, Report of the Board Rate Setting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors, EB-2010-0379, December 4, 2013.

[25] Decision 2012-237, Rate Regulation Initiative, September 12, 2012, pp. 98-104.

[26] AUC Decision 2012-237, pp. 100, 104. The AUC has confirmed its "transition" perspective in 2016, stating that: "Given that current generation PBR plans include a COS-based capital trackers mechanism, which will be mostly replaced in the next generation PBR plans by the K-bar mechanism, the Commission expects that next generation PBR plans will be largely devoid of any significant COS elements. Therefore, the Commission finds merit in including a stretch factor component in the X factor for the next generation PBR plans for all distribution utilities." (Decision 20414, p. 40).

[27] AUC Decision 2012-237, p. 56 (footnote 276).

growth measurements reflect cost-of-service incentives, any heightened incentives under a PBR regime will only show up prospectively. The stretch factor merely anticipates the result of imposing the price cap regime. Its level represents regulators' judgement regarding the effect the new regime will have on the incentives of the firms subject to it.

As such, I propose a stretch factor of zero for EGD and Union in this proceeding, as the transition in Ontario to price cap regulation for these two companies is long in the past.[28]

Q20. What about the OEB's use of stretch factors for its electricity distributors—which exist even though what you label the "transition" to incentive regulation happened long ago. Does that contradict your conclusions about the stretch factor for EGD or Union?

A20. For Ontario, as the subject was raised before the AUC in 2012, the question is whether the stretch factors applied by the OEB to the province's electricity distributors (of 0.2, 0.4 and 0.6) for the then-third generation PBR plan contradicts my opinion that the foundation for the stretch factor lies in the *transition* from cost-of-service regulation to PBR.

I conclude that it does not, in the unique context of Ontario's electricity distribution industry, because of a focus on relative productivity *levels* among the numerous electricity distributors as opposed to the productivity *growth rates* involved in the justification for applying an *X-factor*. My discussion and recommendations for EGD and Union deal strictly with the latter—while the OEB, for what I conclude are good reasons, has included assessments of the former for its business of regulating the prices of the electricity distributors it oversees.

Considerable effort has been expended in North American price cap plans on matters of "statistical benchmarking" of regulated company productivity, or econometric forecasting of what a proper price index should be for a particular firm as part of a broader rate plan. Indeed, Ontario has unique experience with such issues because of its unusually disaggregated electricity sector—comprising many different distribution companies.

28 See Ontario Energy Board, Decision with Reasons in RP-1999-0034, Decision with Reasons in RP-1999-0017, and RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005.

Q21. In that respect, does an *RPI-X* price cap model imply anything about the particular production technology of the regulated firm or allow a regulator to judge whether any particular company is "efficient" compared to its peers?

A21. No, except in unusual circumstances (like needing to regulate the price paths of numerous different electricity distributors). The focus of a PBR plan involving an *RPI-X* formula involves productivity *growth*, and not productivity *levels* (as I show in the next section of my testimony). The AUC dealt with the issue at length in the matter of its electricity and gas distribution utilities, quoting me regarding proposals to determine whether a firm is or is not efficient by looking at benchmark data alone:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie on the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[29]

The AUC observed that in the productivity studies it considered, because the "focus is on rates of change in productivity within an industry, not levels," the unique cost features for particular companies cancel each other out in the process.[30]

Q22. Do you have particular experience with the quality of available objective data that inform utility productivity analyses?

A22. Yes. In addition to my academic work and Dissertation, I have elsewhere written at length for publication about the difficulties of trying to measure efficiency levels of regulated companies under price cap plans with the kind of data that is available.[31] In one 2007 publication, I note the following:

---

[29] AUC Decision 2012-237, p. 57.

[30] Ibid.

[31] See: "Elusive Efficiency and the X-factor in Incentive Regulation: The Törnqvist v. DEA/Malquist Dispute," in Voll, S.P., and King, M.K. (Eds.), *The Line in the Sand: The Shifting Boundaries Between Markets and Regulation in Network Industries*, National Economic Research Associates, White Plains, New York (2007), pp. 95-115; and "Regulating Utility Efficiency "Fast and Slow": the Current Australian Problem, *Natural Gas and Electricity*, Volume 34, No. 5 (October 2017), pp. 28-32

> Empirical data from academic TFP studies show that even the highest quality data (from the U.S. Uniform System of Accounts) produces TFP index growth rates for individual companies that are highly sensitive to vagaries and judgments on how company data is reported to government agencies. Individual data points for specific companies and years in industry-wide TFP analysis are notoriously unstable, even in the best of circumstances.[32]

None of this instability materially undercuts TFP growth studies that encompass many years of data (when the errors cancel each other out)—as in the TFP studies that I presented in Alberta and present in this proceeding.

Q23. Are Ontario's gas distributors in a period of "transition" regarding the move to PBR, as you describe above?

A23. No. It is my understanding that the OEB has pursued PBR regulation for all of its utilities since 1999. Thus, with the proposal in this application, both companies enter into their fourth generation IR plan. I understand that EGD's first PBR plan in the early 2000s was applicable only to the operations and maintenance portion of its costs and was termed "targeted PBR."[33] For Union's first generation plan, the Board identified GDPPI as the inflation factor and 2.5 percent as the applicable *X-factor*.[34] I understand that both utilities resumed filing cost-of-service applications upon expiration of their initial PBR plans.[35]

I also understand that for the 2008-2012 time frame, the Board approved settlement agreements for incentive rate regulation of EGD and Union, with EGD using a "revenue per customer" framework and Union using a price-cap approach. The parties in the EGD settlement could not agree on an *X-factor*, so instead used an inflation coefficient with which to adjust rates.[36] Similarly for the 2014-2018 period, Union came to a settlement agreement with stakeholders and the parties agreed to an inflation coefficient rather than

32 Makholm, "Elusive Efficiency" (2007), p. 105.
33 Ontario Energy Board, RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005, p. 14.
34 Decision with Reasons, RP-1999-0017, pp. 79, 90.
35 Ontario Energy Board, RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005, p. 14.
36 Ontario Energy Board, Decision EB-2007-0615, Schedule A, Enbridge Gas Distribution Revised Settlement Agreement, pp. 10-13; Ontario Energy Board, Decision EB-2007-0606, Schedule A, Union Gas Settlement Agreement, pp. 10-12.

an explicit *X-factor*.[37] EGD utilized the Custom IR option as described for electricity distributors above for its rate adjustment mechanism over the 2014-2019 timeframe.[38]

For Ontario's gas distributors—in contrast to the numerous electric distributors which face altogether different regulatory challenges given the makeup of the industry in the province—I do not find it reasonable to impose a stretch factor for a PBR regime that will be nearly 20 years old when the next price cap framework period begins.

Q24. What about the merger between EGD and Union? Isn't that a "transition" that conceptually could lead to the consideration of a stretch factor?

A24. No. I conclude that that would be "stretching" the meaning of the stretch factor beyond its generally accepted definition. It would also, in my opinion, confuse cause and effect. Let me explain.

Changing the form of regulatory control, away from traditional cost of service regulation to performance-based regulation, applies to regulated utility prices whether the enterprises subject to the new regime remain independent or merge. The change of regime causes the deviation from what would otherwise be straightforward ($I - X$), to include a stretch factor. But the new, performance-based regime is specifically designed to incentivize efficiency, whether lowering costs or enhancing output, so as to increase earnings for the firms involved. There are myriad and inherently unpredictable ways for companies to respond to such a new regime. One of those ways can be to investigate the merger of long-separate utility enterprises, which, if it saves money in the service of consumers, is a good thing. Consumers will share in those saving at future rebasing (and along the way with an earnings sharing scheme, if there is one).

Of course, the considerations for merging utility operations take place in a complex context, and it would be a mistake to draw a straight line between incentive regulation and any particular utility merger. The extent to which anything associated with the change in regulatory regimes incentivized such a merger, it is one of the salutary effects of the new regime. It is not the cause of heightened expectations that drive the stretch factor. It would be a misuse of the stretch factor, as that term is commonly understood, to

[37] Ontario Energy Board, Decision EB-2013-0202, October 7, 2013.
[38] Ontario Energy Board, Decision EB-2012-0459, July 17, 2014.

base it on any particular money-saving or efficiency-enhancing move by the utilities subject to the performance-based regime.

Q25. Is your opinion about measuring productivity growth as opposed to levels a problem for the OEB as it relates to its regulated *electricity distributors*?

A25. No. The issues facing the OEB in the regulation of its wide array of electricity distributors are unique.

My own published criticisms of stochastic frontier analyses and statistical benchmarking of productivity levels do not apply to the challenges of regulating many distributors—most of which are small, municipally-owned enterprises. Indeed, the literature on using statistical techniques to gauge efficiency levels across different operations points to the usefulness of using such methods for gauging efficiency levels "in the public sector, as contrasted with the private sector."[39] Most of Ontario's electricity distribution utilities are in the public sector. As such, I have no criticism of the use of such techniques to gauge the efficiency of the electricity firms that the OEB oversees.

The stretch factors that the OEB used for its third or fourth generation PBR plans for its electric distribution sector, which I understand embody such benchmarking, are different than the type of stretch factors that I and the AUC discussed as part of its 2012 Rate Regulation Initiative decision.[40] The label ("stretch") is the same, but the foundation and function of those factors is different.

III. Economic Theory behind the *X-factor*

Q26. What is this part of your testimony about?

A26. This section serves to provide the theory-oriented reader with the mathematical derivation of the *X-factor*. I explain how the *X-factor* fits into the theory of incentive

[39] Charnes, A., Cooper, W.W., and Rhodes, E., Measuring the Efficiency of Decision Making Units," *European Journal of Operational Research*, Vol. 2 (1978), pp. 429-444 (quoted passage is from p. 433); and Sena, V., "The Frontier Approach to the Measurement of Productivity and Technical Efficiency," *Economic Issues*, Vol. 8, Part 2 (2003), pp. 71-97.

[40] Ontario Energy Board, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008 and Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012.

regulation. I present this theory simply to emphasize that, if an economy wide inflation index is the choice for the inflation factor in *RPI-X* regulation, the *X-factor* has two identifiable components: (1) an input price differential, and (2) a productivity *growth* differential, both compared to the economy as a whole. Because the OEB has accepted the GDP-IPI FDD for the *RPI* part of the formula for Union and EGD in the past, my empirical study focusses on those two elements of the *X-factor*. Having set out the mathematical derivation of the *X-factor* in this section, the next section explains the empirical results of this theory.

Q27. Please proceed.

A27. The annual PBR price cap adjustment formula is designed to emulate competitive markets so that if a company exceeds industry average productivity growth, its earnings will increase, and if it falls short of industry average productivity growth, its earnings will decline. Assume the price cap plan begins with appropriate prices so that the value of total inputs (including a normal return on capital) equals the value of total output for the company as well as the industry. For the industry, we can write this relationship as follows:

$$\sum_{i=1}^{N} p_i Q_i = \sum_{j=1}^{M} w_j \ R_j \ ,$$

where the industry has *N* outputs ($Q_i, i = 1,\ldots,N$) and *M* inputs ($R_j, j = 1,\ldots,M$) and where p_i and w_j denote output and input prices, respectively. We want to calculate a productivity target for a company based on industry average productivity growth.

Focusing on rates of changes (that is, differentiating this identity with respect to time) yields the following relationship:

$$\sum_{i=1}^{N} \dot{p}_i Q_i + \sum_{i=1}^{N} p_i \dot{Q}_i = \sum_{j=1}^{M} \dot{w}_j R_j + \sum_{j=1}^{M} w_j \dot{R}_j \ ,$$

where a dot $(\cdot)$ indicates a derivative with respect to time. Dividing both sides of the equation by the value of output ($Rev = \sum_i p_i Q_i$ or $C = \sum_j w_j R_j$), we obtain this:

$$\sum \dot{p}_i\left(\frac{Q_i}{REV}\right)+\sum \dot{Q}_i\left(\frac{p_i}{REV}\right)=\sum \dot{w}_j\left(\frac{R_j}{C}\right)+\sum \dot{R}_j\left(\frac{w_j}{C}\right),$$

where *REV* and *C* denote revenue and cost. If rev_i denotes the revenue share of output *i* and c_j denotes the cost share of input *j*, then

$$\sum_i rev_i dp_i = \sum_j c_j dw_j - \left[\sum_i rev_i dQ_i - \sum_j c_j dR_j\right],$$

where *d* denotes a *percentage* growth rate: $dp_i = \dot{p}_i \,/\, p_i$. The first term in the equation just above is the revenue-weighted average of the rates of growth of output prices, and the second is the cost-weighted average of the rates of growth of input prices. The term in brackets is the difference between weighted averages of the rates of growth of outputs and inputs. It thus is a measure of the change in TFP. Rewriting the equation to simplify things, we get the following:

$$dp = dw - dTFP\,.$$

The theory underlying the annual adjustment formula implies that the rate of growth of a revenue-weighted output price index is equal to the rate of growth of an expenditure-weighted input price index plus the change in TFP. This equation demonstrates that TFP is the appropriate foundation for a productivity target in the price cap plan. If the plan begins with revenues which just match costs—and if a company attains the same productivity growth as the industry does (measured in terms of TFP), then the company's revenues will continue to match its costs.

Applying this rule, we write the following:

$$dp^* = dw - dTFP$$

where dp^* represents the annual percentage change in industry output prices and dw represents the annual percentage change in input prices. To raise or lower industry output prices in order to track exogenous changes in cost, we write

(1) $$dp = dw - dTFP + Z^*$$

where dp represents the annual percentage change in industry output prices adjusted for exogenous cost changes and Z^* represents the unit change in costs due to external circumstances.[41] Thus, to keep the revenues of the industry equal to its costs, despite changes in input prices, the price cap formula should (i) increase industry output prices at the same rate as its input prices less the target change in productivity growth, and (ii) directly pass through exogenous cost changes.

Equation (1) just above sets the allowed price change as input price changes less TFP growth adjusted for exogenous cost pass-through costs. If the economy-wide inflation rate were taken as a measure of the industry's input price growth and X was its TFP growth target, equation (2) would indeed be the basis for the ideal price adjustment formula. However, there are two potential problems with such an interpretation:

1. Broad inflation measures capture economy-wide *output* price growth, not the industry's input price growth. So even if the industry is a microcosm of the whole economy, a measure that captures economy-wide output price growth would not be an appropriate measure of its input price growth.[42]

2. X is a target TFP growth rate relative to the economy as a whole (or relative to the TFP growth already embodied in economy-wide output price growth). The change in TFP in equation (2) is the absolute TFP growth for the industry. Again, unless economy-wide TFP growth is zero, X is not equal to $dTFP$.

To get from the equation just above the price adjustment formula, we must compare the productivity growth of the industry with the productivity growth of the whole economy. It is difficult to measure input price growth objectively. No agency in Canada (or the United States) maintains an objective index of input prices, industry by industry. A productivity adjustment based on company-provided calculations of changes in their own input price index could be controversial and would not necessarily be based on information outside the company's control. However, by comparing productivity growth of the industry with that of the whole economy, one avoids the difficulty of measuring input price growth.

[41] Note that Z^* can be positive or negative.
[42] Recall that input price growth differs from output price growth by the growth in TFP. Only if national productivity growth were zero could GDP-PI be a good measure of national input price growth.

For the economy as a whole, the relationship among input prices, output prices, productivity, and exogenous cost changes can be derived in the same manner as it was derived in equation (2) above

(2) $$dp^N = dw^N - dTFP^N + Z^{*N}$$

where dp^N is the annual percentage change in an economy-wide index of output prices; dw^N is the annual percentage change in an economy-wide index of input prices $dTFP^N$ is the annual change in the economy-wide total factor productivity and Z^{*N} represents the change in economy-wide output prices caused by the exogenous factors included in equation (1). Subtracting equation (2) from equation (1) gives

$$dp - dp^N = \left[dw - dw^N\right] - \left[dTFP - dTFP^N\right] + \left[Z^* - Z^{*N}\right] \ ,$$

or

(3) $$dp = dp^N - \left[dTFP - dTFP^N + dw^N - dw\right] + \left[Z^* - Z^{*N}\right] \ ,$$

which simplifies to

(4) $$dp = dp^N - X + Z \, .$$

Where the productivity factor (*X*) equals the following:

$$X = (dTFP - dTFP^N) - (dw - dw^N)$$

This equation just above shows that *X* arises if the growth in productivity for the industry in question is *different* than the economy's (the first time), or input cost inflation for the utility is *different* from that for the economy's businesses generally (the second term).

Thus, if the industry achieves a productivity target of *X* and experiences exogenous inflationary cost changes given by *Z*, then the price change that keeps earnings constant is given by equation (4). This price change is given by:

1. the rate of inflation of economy-wide output prices dp^N,
2. less a fixed productivity offset, *X*, which measures the difference in TFP growth, and the difference in input price growth, for the industry and the economy,

3. plus exogenous unit cost changes.

Using the formula (4) to limit price increases has the property that earnings remain the same if a company's achieved productivity differential just meets the historical target *X*. If a company exceeds its productivity target, its earnings will rise; if it falls short of its productivity target, its earnings will fall. This system of rewards and punishments sets up the same incentives that an unregulated company would face in a competitive market, where failure to match industry-average productivity growth results in lower earnings and exceeding industry average productivity growth leads to increased earnings.

IV. Empirical Methods behind the *X-factor*

Q28. What is this section of your testimony about?

A28. I briefly describe my methods for computing TFP growth for the regulated distribution component of local utility operations. Those methods include isolating the distribution component of such utilities and then measuring the various inputs and outputs that result in TFP growth measures. For a longer and more comprehensive explanation of my methodology, please see my report in Alberta Proceeding 566, attached as Exhibit JDM-2. I provide a list of all documents I relied upon as Exhibit JDM-5.

Q29. Please briefly explain your TFP methodology.

A29. My TFP studies for EGD, Union and the distribution industry all utilize the Tornqvist/Theil index methodology to construct output, input and TFP indexes using the various components of outputs and inputs. For my study of the distribution industry I use a population of 65 US electric and combination electric and gas distributors over the time period 1973-2016.[43] I create individual TFP indexes and growth rates for each company and year and then take a weighted average of these growth rates to calculate average TFP

[43] The productivity of electric and gas distribution companies is similar. For one, both industries are highly capital intensive. Further, I examined the difference between TFP growth for both industries using data from Statistics Canada and found no statistically significant difference between the two using both value-added and gross output as the output measure. The data used for this test was taken from Statistics Canada: Table 383-0032. The data series on Multifactor Productivity for the electric and natural gas industry were terminated in 2010.

growth over the time period.[44] For EGD and Union, I use their own company-specific data to calculate average TFP growth for each company. The EGD study spans the years 1993-2016, while the Union study covers the time period 2001-2016.

Q30. How did you measure output in your calculation of TFP growth?

A30. For the distribution industry I use sales volume as the output quantity. I create an output index by combining sales volume for several different customer categories as follows: Residential, Commercial, Industrial and Public. EGD provided sales volume (10^6 m^3) data for roughly the same customer categories. However, I measure sales volume (10^6 m^3) for Union using two customer categories, a General Service category and a Contract category. Union's output quantity measure does not include any output related to its ex-franchise transmission business.

Q31. How did you deal with EGDs and Union's unregulated activities in storage and Union's ex-franchise transmission business when calculating the input costs for labor and materials?

A31. For EGD, I gathered data from its representatives as well as the company's rate filings. It is my understanding that EGD spun off a portion of its unregulated business in 1999. As such, prior to 1999, I use data on wages and salaries and operations and maintenance expense that the company reported were only associated with the distribution business. After 1999, the company ceased reporting its operations in its rate filings in this way. Therefore, I use company total values EGD, as reported in its historic rate filings, for the remaining years.

Further, it was necessary to deal with Union's upstream transmission assets. For O&M and labor costs, I average the historic transmission allocation factors from Union's 2007 and 2013 cost study to estimate the proportion of costs associated with transmission in each year of my study.[45] I then exclude these transmission costs, isolating for only distribution O&M and labor.

44 I use each company's total mWh for each year as the weight.
45 These cost studies can be found in cases EB-2005-0520 and EB-2011-0210, respectively. For labor, this method allocates about 10% of Union's costs to transmission. For O&M expenses about 9% of Union's costs are allocated to transmission.

Q32. How did you deal with these aspects of EGD's and Union's business in your measurement of each company's capital quantity?

A32. I count only EGD's regulated storage plant and distribution plant as distribution capital. I do the same for Union, excluding any aspect of Union's capital associated with its transmission business. Union provided data on its total capital additions and retirements, making it necessary to adjust these data to exclude its transmission lines and other unregulated assets. I did this by first taking out any additions and retirements associated with its transmission business.[46] I then allocate a pro rata share of the remaining capital to distribution using the proportion of distribution plant to total plant (excluding transmission).

V. TFP Results for EGD, Union and the US Energy Distribution Industry

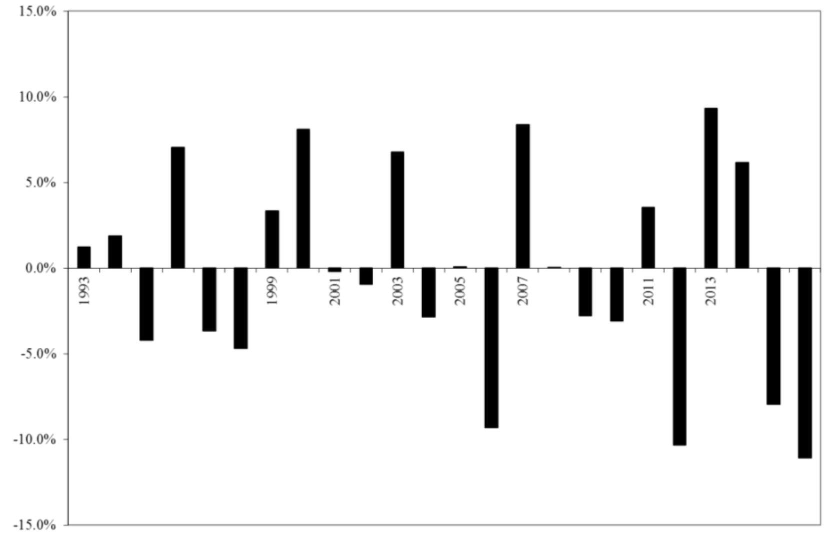
Q33. What are your TFP growth results for EGD?

A33. I find that EGD's average TFP growth over the time period 1993-2016 to be **-0.21 percent**. Comparing this to the Canadian economy wide productivity growth over this same time period results in a relative TFP growth compared to the Canadian economy of **-0.50 percent**.[47] **Figure 1** below summarizes EGD's yearly TFP growth (please see Exhibit JDM-3 for further summary tables and results from each of my three TFP studies).

46 Union's representatives informed me that none of its retirements over the relevant time period were due to the Dawn to Parkway transmission line.

47 Note that Statistics Canada has not yet published a measure of TFP growth for the Canadian economy for 2016. As such, for this year I use the average economy-wide TFP growth for the time period 1993-2015.

Figure 1. EGD TFP growth, 1993-2016

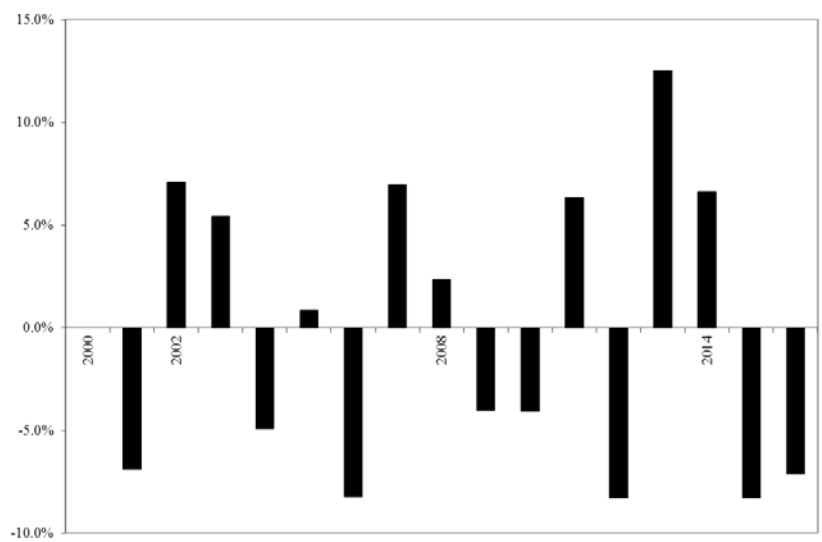


Source: NERA EGD TFP Study

Q34. What are your TFP growth results for Union?

A34. For Union, TFP growth over the time period 2001-2016 averaged **-0.23 percent**, which produces a relative TFP growth factor vis-à-vis the Canadian economy of **-0.06 percent**.[48] **Figure 2** below summarizes Union's yearly TFP growth.

Figure 2. Union TFP growth, 2001-2016



Source: NERA Union TFP Study

[48] For Union, economy-wide TFP growth in 2016 is equal to TFP growth over the time period 2001-2015.

Q35. What about the US regulated energy distribution industry?

A35. I calculate a TFP growth of **0.54 percent** for my population of 65 US electric distribution (and combination electricity and gas) companies over the time period 1973-2016. Comparing this to Canadian economy-wide TFP growth produces an *X-factor* of **0.35 percent**.[49] **Figure 3** below illustrates TFP growth over this time period.

Q36. Do you have any observation on the usefulness of that US data to straight gas distribution companies in Canada?

A36. Yes. That issue was heard at length before the AUC when it accepted my study as the basis for its first generation *X-factor*.[50] Considering the unique quality of the FERC Form 1 data involved, the lack of such data in Canada, the commonality of the distribution tasks for both electricity and gas distributors, and the commonality of the regulatory institutions in Canada and the United States, the AUC accepted the use of that data set over other sources of data for both electricity and gas distributors in the province. It was a decision supported by various other parties in that proceeding who stressed the quality and transparency of that data set for the purpose of close scrutiny. Comparing the TFP growth from that US data to Canadian economy TFP growth is proper, as I discussed previously regarding the fundamental purpose of the *X-factor* (to square Canadian inflation indexes to experienced industry TFP growth).

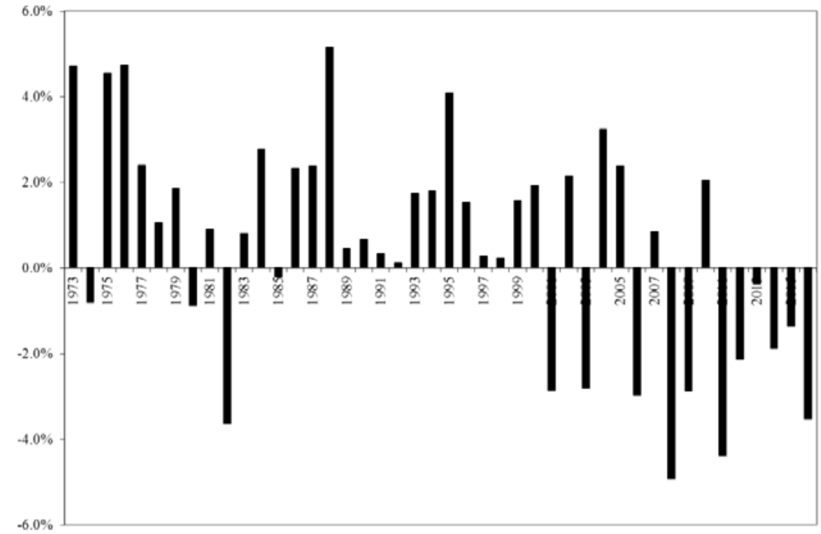
Q37. Do you do a study of input price differences for your analysis of the US regulated energy distribution industry?

A37. Yes. Doing a standard difference in means test, I show that it is not possible to conclude that the data on US distributors input prices and economy wide input prices in the United States come from different series. Exhibit JDM-4 collects my results from this case as well as those I conducted for the AUC proceeding in 2010, for Central Maine Power Company in Maine PUC Docket No. 99-666 and for Utilicorp Networks Canada in Alberta in 2000. The results of my comparison of the input price series' have been consistent over time.

---

49 I use the average TFP growth for the time period 1973-2015 to estimate TFP growth in 2016 for the economy.
50 AUC, Decision 2012-237, September 12, 2012, pp.67-72.

Figure 3. Industry TFP growth, 1973-2016



Source: NERA Industry TFP Study

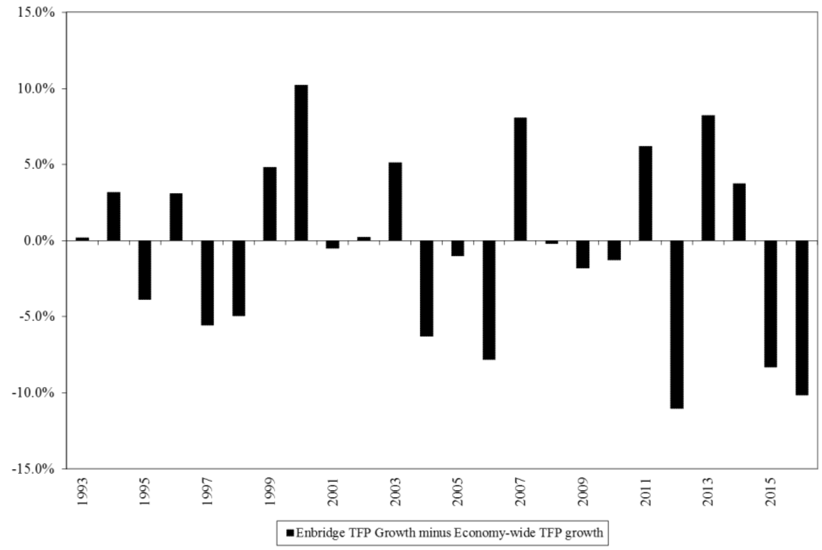
Q38. Do you have any observations about Figures 1, 2 and 3?

A38. Yes. Those figures are where the rubber meets the road, so to speak, regarding a TFP growth study. They conform to a similar bar chart that I first presented for the years 1971-1980 in my 1986 Dissertation.[51] My TFP growth computations for EGD and Union show no reasonably discernable trend—either by themselves or in comparison with the Canadian economy wide TFP growth, as shown in **Figures 4 and 5**, below. Visually examining such results (there is nothing technical in such a visual examination) shows only dispersion around zero—no size or trend to the TFP growth results.

The same is not true of the longer time series results for the US regulated energy distribution companies. There is a definitive trend there that is impossible to overlook. The past six years show negative TFP growth (as do 8 of the last 10 years). Indeed, only 5 of the past 15 years have shown positive TFP growth, whereas 15 of the 15 years before showed positive TFP growth. There is a lot going on with these data that points to a downward trend in measured TFP growth for that population of companies—either by themselves or in relation to the Canadian economy as a whole (shown in **Figure 6**).

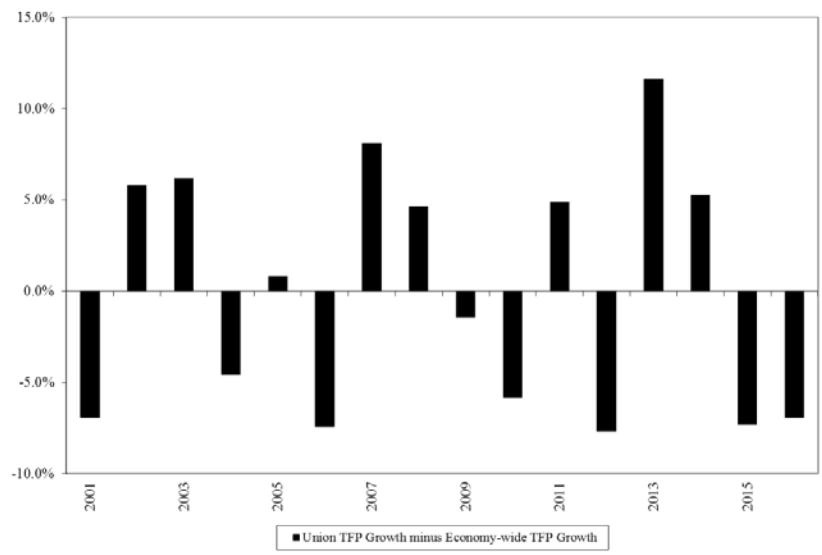
[51] *Sources of Total Factor Productivity in the Electric Utility Industry*, Unpublished Ph.D. Dissertation, University of Wisconsin-Madison, 1986, p. 79.

Figure 4. EGD TFP Growth minus Canadian economy TFP growth, 1993-2016



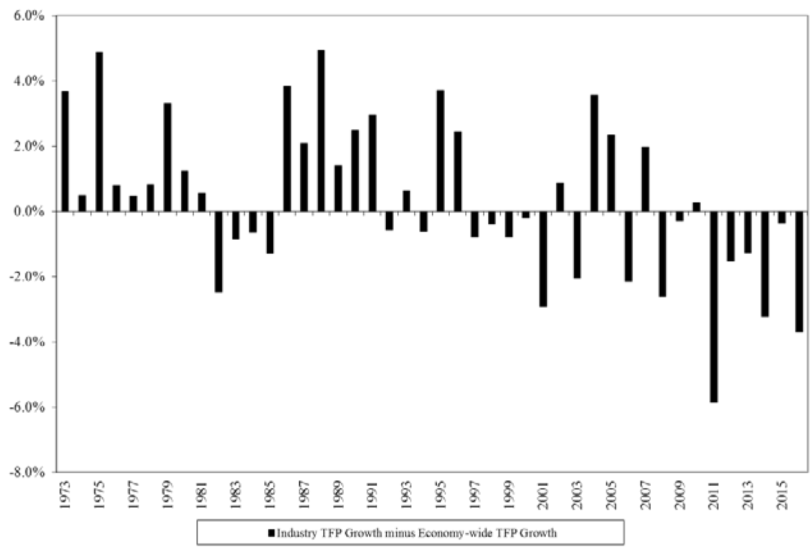
Source: NERA EGD TFP Study and Statistics Canada

Figure 5. Union TFP Growth minus Canadian economy TFP growth, 2001-2016



Source: NERA Union TFP Study and Statistics Canada

Figure 6. Industry TFP Growth minus Canadian economy TFP growth, 1973-2016



Source: NERA Industry TFP Study and Statistics Canada

Q39. Could there be some "structural break" or other economic explanation for such an apparent visual trend?

A39. That is a complicated question. Generally, I recommend against (as I did in the AUC proceeding) making conclusions about economic "structural breaks" based only on the visual examination of data. Indeed, the question of the time period was heavily discussed in that proceeding (including in the Decision), and the AUC supported my conclusion, stating: "NERA's approach of using the longest time period available allows a smoothing out of the effects of various in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle."[52]

I do not recommend splitting the period of measurement. But the analysis since 2009, when I last performed such TFP computations, shows a definitive trend. Given the long-term changes in the energy utility industry since the early 1970s, including the unbundling of distribution services and competition in energy supply, there may well be trends behind such TFP results, for the industry as a whole or for particular objective regions of the United States that disinterested researchers have not yet discovered. I do not hold the opinion that electricity restructuring, as such, necessarily led to a change in

[52] Decision 2012-237, p. 66.

the TFP growth exhibited by the distribution portion of the industry. I also do not have an objective explanation for that apparent trend or knowledge of any scholarly analysis that would do so.[53]

But that trend does inform my conclusions in this case—which is to recommend a simple average TFP growth estimate as applicable to EGD and Union in this case would be unwise. The trend, in a type of analysis that has proven highly credible and has been relied upon in the past, is too apparent for that. Whereas any split in the data would produce a negative TFP growth figure, I determine that it is better to conclude that I cannot definitively reason that there is a prospect for any reliable positive TFP growth for that group of firms for the rebasing period applicable to EGD and Union.

VI. Conclusions on the *X-factor* for EGD and Union

Q40. What do you conclude from your TFP analysis regarding an *X-factor* for the upcoming rebasing period for EGD and Union?

A40. Based on my TFP growth study for the large group of US distribution companies, supported by my comparable analysis of TFP growth for both EGD and Union, I do not recommend an *X-factor* for EGD or Union for their upcoming 10-year rebasing periods. I explain in my testimony that the theory underlying *RPI-X* regulation gives only two reasons for having an *X-factor* in the inflation formula for regulated prices: (1) input price growth differences, or (2) TFP growth differences between the industry and the economy as a whole from which the inflation index comes. For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set). For TFP growth, my analysis of the growth trends in the industry over the period 1973 to 2016, either for the US data set or the data for EGD or Union, does not support an *X-factor* either. Thus, I conclude that the Canadian output

[53] There are scholarly reviews of the past decades of the US electricity industry that I respect, and to some extent they point to possible reasons for poor performance over the past 20 years ("By the mid-2000s the relationship between average and margin cost has largely reversed, and many states expressed a great deal of regret about the decision to restructure"). But those reviews are not sufficient means by which to definitively to change the elements of such a TFP study as I have presented here. See: "The U.S. Electricity Industry after 20 Years of Restructuring," Severin Borenstein and James Bushnell, Energy Institute at Haas Working Paper (May 2015), p. 26.

inflationary index proposed in this case and accepted by the OEB for the companies in the past—GDP-IPI FDD—fairly represents a competitive-like constraint on the output prices for EGD and Union that the *RPI-X* form of regulation calls for.

Q41. What do you conclude regarding any possible "stretch factor?"

A41. I also do not recommend the imposition of a stretch factor. It is fair to say that the consensus, among economists performing productivity studies in PBR plans in North America, is that the purpose of a stretch factor is to reflect the expected productivity growth due to the heightened incentives that accompany a *transition* from a cost-of-service regime to PBR. The OEB has pursued PBR regulation for its utilities consistently since 1999. For *gas distribution* in the province there is nothing, in my opinion, in the generally-accepted foundation for price cap regulation to justify the imposition of a stretch factor for a PBR regime that will turn 20 years old at the start of the upcoming price cap periods.

This is as opposed to *electricity distribution*, which faces distinct industrial, ownership and regulatory challenges that call for different types of regulatory effort on the part of the OEB. Nothing in my testimony is meant as criticism of the measurement of productivity *levels* (as opposed to *growth*), for Ontario's electricity distribution sector or the use of statistical or econometric targets, including their own "stretch" factors, for the many companies, both investor- and municipally-owned, in that sector. Indeed, as discussed in my testimony, the productivity literature provides support for the use of such methods in the presence of such a large number of similarly-situated public enterprises.

Q42. Please explain again why you consider it a misuse of a stretch factor to predicate it on the merger between EGD and Union?

A42. As I said before, it is reasonable to believe that a new, performance-based, regulatory regime will incent different types of utility behavior. As such, there is some merit to concluding that measured productivity over historical periods will not reflect the relative TFP growth capability of a regulated enterprise if it is subject to the new regime. That is the commonly-understood basis for the stretch factor, and such a reason goes away after a number of generations of the new regime.

The stretch factor is not there to anticipate and/or appropriate the gains from any particular efficiency move that utilities may pursue—from more efficient meter reading, to re-organized scheduling and reporting methods, to changes in acquisition procedures, to anything that utilities may re-think and do differently because of the new regime, including merging adjacent service territories. If such actions drive earnings upward and cost downward during a rebasing period, consumers will be the ultimate beneficiaries. But if the stretch factor is repurposed to be a way of trying to take those efficiencies before they happen, then it will undermine the basis for incentive regulation.

Q43. What, in your analysis of the input price differential, lends support for your recommendation of a zero *X-factor* for EGD and Union's next incentive rate setting period?

A43. Using the largest possible TFP data set for North American energy distribution companies, I have consistently never found a statistically significant difference in input prices for the energy distribution industry versus the economy as a whole. I confirm that same result here. That is, I have always found that there is no reason to conclude that the input price inflation faced by the energy utility distribution sector differs from the input price inflation facing the rest of the economy.

Q44. What in your TFP growth analysis for US distribution companies lends support for your recommendation of a zero *X-factor*?

A44. My recommendation rests on the rapidity of the falling measured TFP growth for that group of distribution utilities, since the last time I performed that analysis in 2010—supported by my analysis of consistent EGD and Union data.

For the TFP growth study in that case, I computed average annual TFP growth for the entire population of US distribution companies to be 0.96 percent over the 37 years from 1973 to 2009. Lengthening the period by seven years to 2016, with no methodological changes, reduced the average TFP growth of 0.54 percent—or a growth rate relative to the Canadian economy of 0.35 percent—a precipitous drop that is evident in **Figure 3**. Because of that decline, where the past six years show negative TFP growth (as do 8 of the last 10 years), I cannot conclude that there is a prospect for any reliable positive TFP growth for that group in the next 10 years—either by themselves or in relation to the Canadian economy as a whole. Given the trend evident in such a rapidly-falling TFP growth measurement, and also the unmistakable visual trend in the annual TFP growth measures shown in **Figure 3**, I think that there is no reasonable basis upon which to recommend an *X-factor* based on the difference between distribution TFP growth and economy wide TFP growth, grounded in that data set and the transparent computations applied to it.

My analogous computations for EGD and Union similarly show no TFP growth for the periods over which the companies supplied me with consistent data. The EGD data shows an average TFP growth of -0.21 (for 1993-2016), compared to average TFP growth of -0.23 (for 2001-2016) for Union. Compared to the Canadian economy TFP growth, those numbers remain negative: -0.50 for EGD and -0.06 for Union.

Q45. Does this conclude your testimony at this time?

A45. Yes.

OEB Rule 13A

FORM A

Proceeding: EB-2017-0307

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Jeff D. Makholm. I live at 40 Mount Vernon Street, Boston, in the state of Massachusetts.

2. I have been engaged by or on behalf of Enbridge Gas Distribution and Union Gas Limited to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: November 23, 2017

JEFF D. MAKHOLM
Senior Vice President/Managing Director

National Economic Research Associates, Inc.
200 Clarendon Street
Boston, Massachusetts 02116
(617) 927-4540

Dr. Makholm specializes on the issues of valuation, damages and proper regulated pricing in hard commodity markets and energy industries. With respect to hard commodities (including mining, processing, transport and sale in international markets), he assess production and lease contracts, economic transport costs, and values in local and international markets according to the accepted economic principles of vertical relationships in complex, multi-stage hard commodity production markets. Another of Dr. Makholm's areal of specialty involves the privatization, regulation and deregulation of energy and transportation industries—those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems, railroads and toll roads) and those operating infrastructure business at specific sites, such as oil refineries, electricity generation plants, gas treatment plants, commodity mines, sewage treatment plants and airports. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory and contracting practices. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in court proceedings, arbitral tribunals, regulatory bodies and Parliamentary panels on more than 250 occasions.

Dr. Makholm's clients in North America include privately held oil, gas and utility corporations, public corporations and government agencies. He has represented dozens of gas and electric distribution utilities, as well as both intrastate and interstate oil and gas pipeline companies and oil, gas and electricity producers. Dr. Makholm has also worked with many leading law firms engaged in issues pertaining to the local and interstate regulation of energy utilities.

Internationally, Dr. Makholm has directed an extensive number of projects in the mining, utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), oil pipeline transport financing and regulation (Russia), and valuating in hard commodity mining (Russia, Peru, Colombia, New Zealand). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published many papers in various peer-reviewed and editor-reviewed publications (*Economics of Energy & Environmental Policy*, *Public Utilities Fortnightly*, *Natural Gas and Electricity*, *The Electricity Journal*, *The Energy Law Journal*, *and Competition and Regulation in Network Industries*)—involving a wide range of subjects pertaining to his research work. He is a frequent speaker in the U.S., Europe and elsewhere at conferences and seminars addressing market, pricing and regulatory issues for the energy, commodity and transportation sectors. His latest book, *The Political Economy of Pipelines: A Century of Comparative Institutional Development*, was published by the University of Chicago Press in 2012.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President/Managing Director. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 2000)

Before the International Court of Arbitration, Case No. 1976/CA/ASM, Drummond Coal Mining LLC (DCM), et al, Respondents/Counterclaimants, vs. Ferrocarriles del Norte de Colombia S.A.., Claimant/Counter-Respondent, Expert Report, 20 June 2017. Subject: Market values of mining export losses due to imposed constraints on capacity.

Before the National Energy Board, Expert Report and Reply Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, May 15, 2017. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, November 2016. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the Supreme Court of the State of New York, County of New York, Expert Testimony on behalf of plaintiffs in: S.A. de Obras y Servicios, Copasa and Cointer Chile, S.S. and Azvi Chile, S.A. Agencia en Chile, Plaintiffs v. The Bank of Nova Scotia and Scotiabank Capital, IAS Part 49, Index No. 651649/2013 and 651555/2012. August 10, 2016, Subject: Value of P3 toll road enterprise in Chile.

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-003-2015, March, 2016. Subject: Tolling for pipeline extensions

Before the Superior Court of the State of Delaware in and for New Castle County, Expert Report on behalf of Deere & Company, in C.A. No. N13C-07-330 MMJ CCLD. December 2, 2015. Subject: Value of Power Purchase Agreements in the wind power industry.

Before the Superior Court of the State of California for the County of Los Angeles in the Matter of GAF Materials Corporation v. Paramount Petroleum Corporation, Opinion given September 3, 2015. Case No: BC 481673. Subject: Oil price indexing to set asphalt prices.

Before the United States District Court for the Northern District of Oklahoma, Expert Report on behalf of SFF-TIR, LLC, the Stuart Family Foundation (et al), Case No. 14-CV-369-TCK-FHM, June 30, 2015. Subject: Fair value of shares in a pipeline industry services firm.

Before the International Chamber of Commerce Expert Report on behalf of STP Energy Pte Ltd. Subject: Valuation of offshore oil and gas exploration permit, April 29, 2015.

Before the Régie de l'énergie, Written Evidence on behalf of Gaz Métro. Subject: Pricing of gas distribution system expansion, January 20, 2015

Before the Supreme Court of Western Australia, Filed Statement on behalf of North West Shelf Pty Ltd, Subject: Value and interpretation of gas swaps agreement, December 24, 2014.

Before the District Court of Tarrant County, Texas, 17th Judicial District, Expert Report of Jeff D. Makholm on behalf of OAO Gazprom, et al, Subject: Valuation of failed LNG import project, November 14, 2014.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2014, July 2014. Subject: Effectiveness of toll design//regime in settlement.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-001-2014, July 10, 2014. Subject: Tolling for pipeline extensions.

Before the National Energy Board, Expert Testimony on behalf of Alliance Pipeline, May 22, 2014. Subject: Restructuring services/tolls.

Before the Economic Regulation Authority of Western Australia on behalf of ATCO Gas Australia, March 2014. Subject: Cost accounting for gas pipeline regulation.

Before the 298th Judicial District Court of Dallas County, Texas, Expert Testimony on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, February 2014. Subject: Assessment of causation and valuation of damages from lost crude oil pipeline opportunity.

Before the National Energy Board, Expert Testimony on behalf of Enbridge Gas Distribution Inc. and Union Gas limited, Hearing Order MH-001-2013, November 1, 2013. Subject: Tolling issues involving pipeline abandonment.

Before the National Energy Board, Expert Report and Direct Evidence on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2013, July 26, 2013. Subject: Contract renewal provisions.

Before the 298th Judicial District Court of Dallas County, Texas, Supplemental Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, July 24, 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Rebuttal Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, March 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Direct Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, January 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the Alberta Public Utility Commission, Direct Testimony on behalf of ATCO Electric and ATCO Gas, Proceeding ID #2131, December 2012. Subject: Analysis of ATCO Electric's and ATCO Gas' capital tracker proposals

Before the American Arbitration Association, Expert Report with Dr. Victor P. Goldberg, Case No. AAA No. 16 132 Y 00502 11. December 17, 2012. Subject: Confidential Arbitration.

Before the National Energy Board, Written Evidence on behalf of FortisBC Energy Inc., Hearing Order GH-001-2012, May 29, 2012. Subject: Tariff treatment for pipeline extensions to new Canadian gas production regions.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Market Area Shippers Group, Hearing Order RH-003-2011, March 2012. Subject: Assessment of TransCanada's omnibus restructuring proposal and commentary on Market Area Shippers Group's alternative solution.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Alberta Public Utility Commission (with Agustin J. Ros). Reply Expert Report. Application No. 1606029, AUC Proceeding 566. February 22, 2012. Subject: Update to TFP analysis and review of PBR plans for the Commission's performance-based regulation initiative.

Before the State Corporation Commission of the State of Kansas, Testimony on Behalf of Coffeyville Resources Refining & Marketing, LLC, Docket No. 12-MDAP-068-RTS. October 25, 2011. Subject: Reasonable ratemaking methodology.

Before the United States Federal Energy Regulatory Commission, Prepared Direct Testimony in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. October 17, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Pre-filed Rebuttal Testimony on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy. Docket Nos. 11-03003, 11-03004 & 11-03005. August 3, 2011. Subject: Prudence of hedging practices.

Before the United States Federal Energy Regulatory Commission, Affidavit in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. February 28, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Nevada Power Company d/b/a NV Energy, 2011 Gas and Electric Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of hedging practices.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Sierra Pacific Power Company d/b/a NV Energy, 2011 Gas Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of gas hedging practices.

Before the Federal Energy Regulatory Commission and the State of Alaska Regulatory Commission, Prepared Direct Testimony on behalf of Trans Alaska Pipeline System. Docket No. IS09-348-004, *et al*. January 21, 2011. Subject: Prudence of capital rehabilitation costs.

Expert report filed before the Alberta Public Utility Commission (with Agustin J. Ros). Application No. 1606029, AUC Proceeding 566. December 30, 2010. Subject: Total factor productivity study for use in the Commission's performance-based regulation initiative.

Before the Commonwealth of Kentucky, Edmonson Circuit Court. Opinion on behalf of plaintiff in Honeycutt vs. Atmos Energy Corporation. Docket No. 09-CI-00198 and 10-CI-00040. September 10, 2010. Subject: Valuation of natural gas for royalty computations.

Before the Régie de l'Energie, Direct Testimony on behalf of Hydro-Québec TransÉnergie. Demande R-3738-2010. August 2, 2010. Subject: Economic analysis of issues related to the regulatory policies for network upgrades.

Before the Public Utilities Commission of Nevada, Pre-Filed Supplemental Direct Testimony on behalf of Nevada Power Company, Sierra Pacific Power Company d/b/a NV Energy (electric and gas departments), Docket No: 10-03003, 10-03004, 10-03005. May 5, 2010. Subject: Gas hedging.

Before the Arkansas Public Service Commission, Rebuttal Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. March 24, 2010. Subject: Justification of the operation of a multi-year formula rate plan.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Pre-Filed Direct on behalf of Nevada Power Company, Docket No. 10-03003. February 26, 2010. Subject: Prudence of gas purchase costs.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718 and New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. February 12, 2010. Subject: Cost of equity capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company , Docket No. 09-09001. December 15, 2009. Subject: Gas hedging plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-07003. December 15, 2009. Subject: Gas hedging plan.

Before the New York State Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718. September 17, 2009. Subject: Cost of capital and capital structure.

Before the New York State Public Service Commission, Direct Testimony on behalf of New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. September 17, 2009. Subject: Cost of capital and capital structure.

Before the Arkansas Public Service Commission, Direct Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. September 4, 2009. Subject: Justification of the operation of a multi-year formula rate plan.

Submission before the New Zealand Commerce Commission, on behalf of Orion New Zealand Limited, July 31, 2009. Subject: Theory and practice of price cap regulation.

Before the Hawaii Public Utilities Commission, Testimony on behalf of Hawaiian Electric Company Inc., Docket No. 2008-0083. July 2009. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-02____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 09-02_____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Connecticut Natural Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Southern Connecticut Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of Lone Star Transmission, LLC. Docket No. 35665. November 14, 2008. Subject: Licensing of new electricity transmission projects.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of The Dayton Power and Light Company. Case No. 08-1094-EL-SSO. October 10, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. September 25, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. April 29, 2008. Subject: Cost of equity.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. April 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Case No. 07-M-0906. January 31, 2008. Subject: Regulatory philosophy/ merger issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. January 14, 2008. Subject: Stand-alone costs and cost allocation issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No. 07-09016. January 11, 2008. Subject: Allocation of pipeline transport costs.

Before the Illinois Commerce Commission, Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. January 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Consolidated Edison Company of New York, Docket No. OA08-13-000. January 7, 2008. Subject: Planning and allocation of electric transmission costs.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. December 14, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the New Hampshire Public Service Commission, Docket No. DE 07-064, invited appearance on an expert panel to present perspectives and answer questions on policies and practices regarding retail gas and electric distribution rate "decoupling," November 7, 2007.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-05019. May 15, 2007. Subject: Prudence of gas purchase costs.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., *et al.*, Debtors, Case No. 03-17949 (PCB) (Jointly Administered), April 20, 2007. Subject: Discount rate for contract rejection damages.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. April 19, 2007. Subject: Stand-alone costs and cost allocation issues.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., et al., Debtors, Case No. 03-17949 (PCB) (Jointly Administered), March 23, 2007. Subject: Discount rate for contract rejection damages.

Before the United States District Court, District of Kansas, Expert Report on behalf of J.P. Morgan Trust Company, *et al*. in the matter of J.P. Morgan Trust Company, *et al*. V. Mid-America Pipeline Company, *et.al*., Docket No. 05-CV-2231-CM/JPO. March 21, 2007. Title: "Harm to Farmland's Coffeyville Refinery Expert Report", by Jeff. D. Makholm.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Nevada Power Company, Docket No. 07-01022. January 16, 2007. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of the State of Hawaii, Supplemental Testimony on behalf of Hawaii Electric Light Company, Inc., Docket No. 05-0135. December 29, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of the State of Hawaii, Testimony on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386. December 22, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. December 1, 2006. Subject: Stand-alone costs and cost allocation issues.

Before the State of New Jersey Board of Public Utilities, Prepared Reply Testimony on behalf of Public Service Electric & Gas, OAL Docket No. PUC1191-06 and BPU Docket No. EO05111005. November 3, 2006. Subject: Unregulated contract prices for telecommunication conduit rental contracts.

Before the State of New Jersey Board of Public Utilities, Rebuttal Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, October 10, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of the State of Alaska, Docket No. OR05-2-001, August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

Before the Maine Public Utilities Commission, Response to the Bench Analysis on behalf of Central Maine Power Company, Docket 2005-729. May 19, 2006. Subject: Specification of productivity offset for price cap formula.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 05-12001. May 17, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company (Gas Division, WestPac Gas), Docket No. 06-0516. May 15, 2006. Subject: Prudence of the company's gas hedging strategy.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, March 29, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Nevada Power Company, Docket No.06-01016. January 17, 2006. Subject: Prudence of the company's gas hedging costs.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony on behalf of the Public Intervenor, Board Reference 2005-002. December 30, 2005 (original filing), January 23, 2006 (updated filing). Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No.05-12001. December 1, 2005. Subject: Prudence of the company's gas hedging costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No.05-9016. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Nevada Power Company, Docket No.05-9017. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Ohio, Supplemental Testimony on behalf of The Dayton Power and Light Company. Case No. 05-276-EL-AIR. September 26, 2005. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. May 12, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Reply Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). April 12, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No 05-1028. April 12, 2005. Subject: Prudence of gas purchase costs.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. April 5, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). March 22, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of the State of Oregon, Direct Testimony and Exhibits on behalf of Portland General Electric. Docket No.UE-88 Remand. February 15, 2005. Subject: The cost consequences of abandoning the regulatory compact in Oregon on prudent invested capital.

Before the Louisiana Public Service Commission, testimony on behalf of Entergy Gulf States, Ind., and Entergy Louisiana, Inc., in Re: Analysis of Competitive Implications, Consolidated Docket No. U-21453, et al, January 13, 2005. Subject: Retail electricity competition.

Before the Public Utilities Commission of Nevada, Testimony and Exhibits on behalf of Sierra Pacific Power Company. Docket No 05-1028. January 5, 2005. Subject: Prudence of gas purchase costs.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility commission of Oregon, Direct Testimony on behalf of Portland General Electric. Docket No. UE-165. November 17, 2004. Subject: Power supply risk related to PGE's hydroelectric generation sources.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Nevada Power Company. Docket No. 04-11028. November 10, 2004. Subject: Examination of the prudence of gas purchase and hedging decision in the Company's 2004 deferral case.

Before the Illinois Commerce Commission, Testimony on behalf of Nicor Gas Company. Docket No. 04-0779. November 1, 2004. Subject: Cost of Capital.

Rebuttal Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 15, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the International Center for the Settlement of Investment Disputes, Testimony on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina in Paris, France, October 11th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Circuit Court of Fairfax, Virginia, Testimony on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. October 1, 2004. Subject: Valuation of capacity expansion project.

Expert Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 1, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the London Courts of International Arbitration, Rebuttal Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. September 17, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before the London Courts of International Arbitration, Expert Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. August 6, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before International Center for the Settlement of Investment Disputes, Rebuttal Report on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina, April 15th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-12002. March 29, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 03-10001 and 03-10002. February 5, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the New Zealand Commerce Commission, Testimony on behalf of Orion New Zealand. November 5, 2003. Subject: Productivity measures used in resetting the price path thresholds for electricity distributors in New Zealand.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of FairPoint New England Telephone Companies. July 11, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. May 14, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-1014. May 5, 2003. Subject: Prudence of gas procurement and hedging program.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of FairPoint New England Telephone Companies. April 7, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 02-11021. March 31, 2003. Subject: Prudence of gas procurement and hedging program.

Before Federal Communications Commission, Testimony on behalf of Iowa Telecommunications Services, Inc. Case No. March 25, 2003. Subject: Cost of capital.

Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ERO3-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

Before the New York State Public Service Commission, Affidavit in support of Rochester Gas and Electric Corporation's Response to Staff's November 8, 2002 filing. Case No. 02-E-0198, 02-G-0199. November 14, 2002. Subject: Respond to staff's filing with respect to the rate-of-return and risk impacts of various regulatory mechanisms.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of American Electric Power Company, Inc., Mutual energy CPL, LP, Mutual Energy WTU, LP and Centrica PLC, Centrica N.S. Holding, Inc., Centrica Holdco, Inc.. Case No. 25957. October 28, 2002. Subject: Impact of the merger on competition in the retail electric market.

Before the International Center for the Settlement of Investment Disputes, Expert Testimony on behalf of Azurix Corp in the case of Azurix Corp v. Government of Argentina, October 15, 2002. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New York Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. September 30, 2002. Subject: Cost of capital

Before the Connecticut Department of Public Utility Control, Update and Rebuttal Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, April 4, 2002. Subject: Cost of capital.

Before the State of New York Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. February 15, 2002. Subject: Cost of capital.

Before the Alberta Energy and Utilities Board, Update of Evidence on behalf of UtiliCorp Networks Canada, November 30, 2001. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the Connecticut Department of Public Utility Control, Direct Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, November 15, 2001. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, October 24, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony on behalf of Community Service Telephone Company. September 6, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of the Association of Oil Pipe Lines. Case No: OR96-2-000. June 21. 2001. Subject: Light-handed regulation of oil pipeline tariffs.

Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility Commission of the State of Oregon, Rebuttal Testimony on behalf of Portland General Electric Company. May 21, 2001. Subject: Cost of capital.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of Community Service Telephone Company. April 4, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the State of New Jersey Board of Public Utilities, Cross-Answering Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564, March 26, 2001. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the Indiana Utility Regulatory Commission, Testimony on behalf of Tipton Telephone Company, Inc, February 23, 2001 (with C. Zarkadas). Subject: Cost of capital.

Before the Supreme Court of Victoria at Melbourne, in the matter of an appeal brought by TXU Electricity Limited of the Final Determination of the Office of the Regulator General of the 2001 to 2005 tariffs for the Victorian electricity distributors. Testimony on behalf the Office of the Regulator General, February 11, 2001. Subject: The distinctions between price cap and rate of return regulatory practices.

Before the Australian Competition Tribunal. Statement on behalf of the National Competition Council regarding the application under section 38(1) of the Gas Pipelines Access Law for review of the decision by the Minister for Industry, Science and Resources to Cover (i.e., regulate) the Eastern Gas Pipeline pursuant to the provisions of the National Third Party Access Code for Natural Gas Pipeline Systems and the Gas Pipelines Access Law, January 19, 2001. Subject: Evaluation of the criteria for regulating an interstate gas pipeline.

Before the Public Utility Commission of Texas. Rebuttal Testimony on behalf of American Electric Power Texas Companies (Central Power & Light Company, Southwest Electric Power Company, West Texas Utilities Company), Entergy Gulf States, Inc., Reliant Energy HL&P, Southwestern Public Service Company, Texas-New Mexico Power Company, and TXU Electric Company. October 27, 2000. Subject: Capital structure and allowed return on equity.

Before the Federal Energy Regulatory Commission, "Assessment of PJM Owner's Transmission Enhancement Package," prepared in support of the PJM (Pennsylvania, New Jersey, Maryland) electricity transmission owners as part of their Order No. 2000 compliance filing. Docket No. RT01-2, October 11, 2000. Subject: Analysis of incentive package for transmission efficiency.

Before the Appeal Panel under Section 38(2) of the Office of the Regulator-General Act 1994, Victoria, Australia. In the matter of an appeal pursuant to s.37 of the Act brought by United Energy Ltd., Testimony on behalf of the Office of the Regulator General, October 10, 2000. Subject: The distinctions between price cap and traditional cost-based regulatory practices.

Before the Alberta Energy and Utilities Board, Evidence on behalf of UtiliCorp Networks Canada, September 1, 2000. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the State of Maine Public Utilities Commission, Surrebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, August 10, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564, July 26, 2000. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, June 22, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 12, 2000. Subject: Investigation Concerning the Unbundling of delivery Services under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 5, 2000. Subject: Investigation Concerning the Unbundling of delivery Services under Section 16-108 of the Public Utilities Act.

PUBLICATIONS

"Electricity Deregulation under Siege," *Natural Gas and Electricity*, Volume 34, No. 5 (August 2017), forthcoming.

"The Mysterious Cost of Capital for Energy Utilities," *Natural Gas and Electricity*, Volume 34, No. 3 (June 2017), pp. 28-32

"Climate Change, "Grid Neutrality," and Electricity Distributors," *Natural Gas and Electricity*, Volume 34, No. 1 (April 2017), pp. 28-32.

"The Interaction of Pipelines and Geography in Support of Fuel Markets," in Warf, B.L., (Ed.) *The Handbook on Geographies of Technology*, Edward Elgar, Cheltenham, UK (2017), pp. 347-361.

"Brexit and Divestiture Provides New Hope for "British" Gas," *Natural Gas and Electricity*, Volume 33, Number 6, February 2017.

"When Worlds Collide: Universal Challenges in Natural Gas and Electricity Markets," *Natural Gas and Electricity*, Volume 33, Number 7, December 2016.

"The REVolution Yields to a More Familiar Path: New York's Reforming the Energy Vision (REV)," *The Electricity Journal* (November 2016). pp. 48-55.

"The Politics of US Oil Pipelines: The First Born Struggles to Learn from the Clever Younger Sibling," *Energy Law Journal*, November 11, 2016, (with Laura T.W. Olive). pp. 409-427.

"Will LNG Rescue World Gas Market? Maybe a Little," *Natural Gas and Electricity*, Volume 33, Number 5, October 2016.

"Distributed Energy and Low Carbon vs. Consumers, Regulators and Tin Men," *Natural Gas and Electricity*, Volume 33, Number 3, August 2016.

Section Editor (Midstream Sector), *Current Sustainable and Renewable Energy Reports*, Springer (ISSN: 2196-3010), 2016.

"There is But One True Hub, and His Name is Henry," *Natural Gas and Electricity*, Volume 32, Number 11 (June 2016). pp. 27-30.

"El Nino's Uneven Disruption of World's Electricity Systems", *Natural Gas and Electricity*, Volume 32, Issue 9 (April 2016), pp. 29–32.

"Choose your path: the future for Australia's gas market." *The Australian Pipeliner*, April 2016.

"Why Does Most Shale Gas Worldwide Remain in the Ground?" *Natural Gas and Electricity*, Volume 32, Issue 7 (February 2016), pp. 29–32

"Utility Regulation Principles Vary Widely Country to Country," *Natural Gas and Electricity*, Volume 32, Issue 5 (December 2015), pp. 31–32

"'Entry/Exit' Pipeline Pricing in Gas "Islands" Enables EU to Resist Competition," *Natural Gas and Electricity*, Volume 32, Issue 3 (October 2015), pp. 27–29

"Regulation of Natural Gas in the United States, Canada, and Europe: Prospects for a Low Carbon Fuel," *Review of Environmental Economics and Policy*, Vol. 9, Issue 1 (Winter 2015), pp. 107-127.

PUBLICATIONS (CONTINUED)

"Congress Can Stop the Boom in Oil Tank Cars," The London School of Economics daily weblog on American Politics and Policy, 30 March 2015.

"If Europe wants to embrace natural gas as a bridge to a low-carbon future, it should draw from America's success," The London School of Economics daily weblog on European Politics and Policy, 21 March 2015.

"Ensuring Natural Gas Availability," paper included in MIT Energy Initiative 2013 MITEI Symposium publication *Growing Concerns*, *Possible Solutions: The Interdependency of Natural Gas and Electricity Systems*, April 16, 2013.

"Marginal Costs with ~~Wings~~ a Ball and Chain: Pipelines and Institutional Foundations for the U.S. Gas Market," *Economics of Energy and Environmental Policy*, Vol. 1, Issue 1 (2012).

"North American Performance-Based Regulation for the 21st Century," *The Electricity Journal*, May 2012, Vol. 25, Issue 4, (with Agustin J. Ros and Stephen C.W. Collins).

The Political Economy of Pipelines: A Century of Comparative Institutional Development, The University of Chicago Press, Chicago and London (2012). Chinese-language edition published by the Petroleum Industry Press, Beijing (2016).

"Real Unbundlings: The Foundation for a Competitive Gas Market in the United States," *Competition and Regulation in Network Industries*, Vol. 12, No.4 (2011).

"Zone of Reasonableness: Coping with Rising Profitability a Decade after Restructuring," *Public Utilities Fortnightly*, 1 July 2011 (with Kurt Strunk).

"Fueling the Price of Power (and Gas): The Rising Profitability of Pipelines and the Need for Collective Action," *The Electricity Journal*, June 2011, Vol. 24 Issue No.5. pp. 7-13 (with Wayne Olson).

"Seeking Competition and Supply Security in Natural Gas: the US Experience and the European Challenge," in Lévêque, F., Glachant, J-M., Barquín, J., von Hirschhausen, C., Holz, F., and Nuttal, W.J., (eds.), *Security of Energy Supply in Europe*, Edward Elgar, Cheltenham, UK (2010), pp. 21-55.

"Decoupling" for Energy Distributors: Changing 19th Century Tariff Structures To Address 21st Century Energy Markets," *Energy Law Journal*, Vol. 29, No.1 (2008), pp.157-172.

"Electricity Transmission Cost Allocation: A Throwback to an Earlier Era in Gas Transmission," *The Electricity Journal*, Vol. 20, Issue 10 (December 2007), pp. 13-25

"Elusive Efficiency and the X-Factor in Incentive Regulation: The Törnqvist v. DEA/Malquist Dispute," in Voll, S.P., and King, M.K. (Eds.), *The Line in the Sand: The Shifting Boundaries Between Markets and Regulation in Network Industries*, National Economic Research Associates, White Plains, New York (2007), pp. 95-115.

"Theoretische Rechtfertigung des X-Faktors" ("Theoretical Justification for X-Factors"), *Energiewirtschaftliche Tagesfragen*, Vol. 47, No. 3 (March 2007), pp. 50-52.

"Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business," with Meehan, E.T., and Sullivan, J.E., *The Electricity Journal*, Vol. 19, No 3 (April 2006), pp. 11-29.

"The Thaw: The End of the Ice Age for American Utility Rate Cases," with Parmesano, H., *The Electricity Journal*, Vol. 17, No. 4 (July 2004), pp.69-74.

PUBLICATIONS (CONTINUED)

"In Defense of the 'Gold Standard," *Public Utilities Fortnightly*, Vol. 141, No. 10 (May, 2003), pp. 12-18.

"Incentive Regulation Meets Electricity Transmission on a Grand Scale: FERC Order No. 2000 and PBR," *The Electricity Journal*, Vol. 13, No. 2 (May 2000), pp.57-64.

"ISO's Not the Answer for Gas," *Natural Gas*, Vol. 14, No. 5 (December 1997), pp. 1-6.

Utility Regulation 1997: Economic Regulation of Utilities and Network Industries Worldwide (Chapter on United States), Center for the Study of Regulated Industries, (ISBN 1-901597-00-8) 1997.

"X Marks the Spot: How to Calculate Price Caps for the Distribution Function," *Public Utilities Fortnightly*, Vol. 135, No. 22 (December 1997), p. 52.

"FERC Takes the Wrong Path in Pricing Policy," *Natural Gas*, Vol. 12, No. 3 (September, 1995), pp. 7-11.

The Distribution and Pricing of Sichuan Natural Gas, Chonxing University Press, Chonxing, China (ISBN 7-5624 -1006-2/F 94), 1995.

"Secondary Market Can Compete," *Natural Gas*, Vol. 11, No. 3 (October 1994), pp. 13-17.

"Gas Pipeline Capacity: Who Owns It? Who Profits? How Much?" *Public Utilities Fortnightly*, Vol. 132, No. 18 (October 1994), pp. 17-20.

"Calculating Fairness," with Sander, D.O., *Public Utilities Fortnightly*, Vol. 131, No. 21 (November 1993), pp. 25-29.

"The Risk Sharing Strawman," *Public Utilities Fortnightly*, Vol. 122, No. 1 (July 1988), pp. 24-29.

"The FERC Discounted Cash Flow: A Compromise in the Wrong Direction," with C. J. Cicchetti, *Public Utilities Fortnightly*, Vol. 120, No.1 (July 1987), pp. 11-15.

UNPUBLISHED WORKING PAPERS

"The Political Economy of "P3" Public-Private Partnerships: Chilean Lessons for Rebuilding US Infrastructure," NERA publication, March 25, 2017.

"A Square Regulatory Peg in a Round Industry Hole: Europe's Gas Industry Problems," NERA publication, 11 January 2017.

"2011 Speech Revisited—Whither the "Fourth Gas Package" for the EU: Dealing with Paralysis in Europe's Gas Industry," NERA publication, 8 December 2016.

"A Half-Century of Computing the Cost of Capital for Utilities at NERA," NERA publication, November 9, 2015.

"Pipeline Capacity Rights to Support a Competitive Gas Market: Theory and Applications", with Nina Hitchins, NERA publication, September 26, 2015.

"A Petroleum Tanker of a Different Color: Obstacles to an LNG-based Global Gas Spot Market," with Laura T.W. Olive, NERA Publication, August 18, 2015.

"Seeking Competition and Supply Security in Natural Gas: The US Experience and European Challenge," Prepared for the 1st CESSA Conference, Berlin University of Technology, Berlin, Germany, May 31, 2007.

"The Theory of Relationship Specific Investments, Long-Term Contracts and Gas Pipeline Development in the United States," paper given at the Conference on Energy Economics and Technology at the Dresden University of Technology, Dresden, Germany, April 21, 2006.

"Benchmarking, Rate Cases and Regulatory Commitment," paper given at the Australian Competition & Consumer Commission's Incentive Regulation and Overseas Developments Conference, Sydney, Australia, November 14, 1999

"Price Cap Plans for Electricity Distribution Companies Using TFP Analysis," with Quinn, M.J., NERA Working Paper, July 23, 1997.

"Rocks on the Road to Effective Regulation: The Necessary Elements of Sound Energy Regulation," paper presented at the Brazil-U.S. Aspen Global Forum, December 5, 1996.

"Profit Sharing and "Sliding Scale" Regimes," NERA Working Paper, Quinn, M.J., and Augustine, C., February 29, 1996.

"Four Common Errors in Applying the DCF Model in Utility Rate Cases," with Sander, D.O., NERA Working Paper, February 1992.

"Pareto Optimality through Non-Collusive Bilateral Monopoly with Cost-Of-Service Regulation," with Cicchetti, C.J., *Energy and Environmental Policy Center*, Harvard University, Working Paper, April 1988.

RECENT SPEECHES

"The New Market Conditions in Latin America's Energy Space," Latin Lawyer 8th Annual Oil and Gas Conference, Mexico City, 18 May 2017.

"The Uncertain Connection between Unbundled Electricity Distributors and Interstate Pipeline Capacity," Law Seminars International Energy in the Northeast Seminar, with Laura T.W. Olive, PhD. Boston, MA, September 23, 2016

"The Difficult Economics of a Worldwide LNG Commodity Market," International Bar Association Annual Conference, Oil and Gas Law Committee Section. Washington DC, September 22, 2016

"How to Make LNG Accessible to All of Europe?" CEER Workshop. Athens, Greece, September 12, 2016.

"Gas Markets, Gas Use and Europe's Gas Supply from the East," Eurasian Natural Gas Infrastructure Conference, Istanbul, Turkey, June 9, 2015

"International Perspective on Pathways for Gas Market Reform in Australia," Australian Domestic Gas Outlook, 2016, Sydney, Australia, March 8, 2016.

"What does a Gas Market Need?" Australian Domestic Gas Outlook 2016 In-Depth Learning Session B. Sydney, Australia, March 7, 2016.

"Gas as the Low-Carbon Bridge Fuel? Not without a Lot of Trouble," International Bar Association, Vienna, Austria, October 8, 2015.

"Gas Market Centers and Balancing in the US: Facilitating the Competitive Entry and Trade in Gas," FSR Specialized Training on the Regulation of Gas Markets, Florence, Italy, March 27, 2015.

"Gas Market in the US: Are there some lessons for Europe?" Gas Infrastructure Europe (GIE) Annual Conference 2014, Berlin, Germany, June 13, 2014.

"Ensuring Natural Gas Availability," MIT Energy Initiative, 2013 MITEI Symposium, Cambridge, Massachusetts, April 16, 2013.

"Regulating Access to Gas in North America," Florence School of Regulation, FSR Specialized Training, Florence, Italy, March 13, 2013.

"The Role of Regulation and the Challenges Going Forward," Speech given at the 10th Annual Tufts Energy Conference, Panel 3: The Natural Gas Boom. Medford, Massachusetts, February 21, 2015.

"Natural Gas in the Transformation Process in Europe," German Institution for Economic Research (DIW Berlin), Schumpeter Hall, Berlin, Germany. May 15, 2012.

"The Trouble with Europe: Infrastructure, Institutions and Investment," Keynote Speech at EPRG Winter Seminar 809. Cambridge, U.K., December 5, 2011.

"Regulating Gas TSO's in Europe: Where are all the Pipelines?" Oil and Gas Pipes Global Conference. London, U.K., November 29, 2011.

"Security of Supply in Europe," Florence School of Regulation, State of the EU Conference at the European University Institute. Florence, Italy, May 10, 2012.

"Regulating Gas Pipelines: United States and Europe," Florence School of Regulation, FSR Summer Course Advanced Training on Gas Markets. Florence, Italy, March 23, 2011.

"Foundation for Regulating Pipelines, United States and Europe: Two Different Regulatory Worlds," Florence School of Regulation Summer Course on Regulation of Energy Utilities. Florence, Italy, June 30, 2010.

"Governance and the Electricity Sector," Governance and Regulation in the Electricity Sector Conference. Toronto, Ontario, June 4, 2010.

"Public Utility Companies and Regulatory Risk," Saul Ewing's 4th Annual Public Utility Symposium. Philadelphia, PA, May 24, 2010.

"It's All About Inland Transportation," US Gas Pipelines Reflect What's Happening in Europe," Florence School of Regulation Specialized Training on Regulation of Gas Markets. Florence, Italy, March 24, 2010.

"Windmills and Wires: FERC Rate Cases, Transmission Cost Allocation, and Renewable Power Development," Law Seminars International Sixth Annual National Conference on Today's Utility, Las Vegas, Nevada, February 11, 2010.

"The East-West Energy Corridor and Europe's Energy Security," The Brookings Institution conference on Turkey, Russian and Regional Energy Strategies, Washington D.C., July 15, 2009.

"Understanding U.S. Gas Pipelines," Florence School of Regulation, FSR Summer School on Regulation of Energy Utilities. Florence, Italy, June 24, 2009.

"Vertical Relations in Energy Markets: On the Role of Contracts and Other Legal Entitlements in the U.S. Gas Transport Market", Vienna University of Economics and Business, Workshop 2009. Vienna, Austria, May 29, 2009.

"Institutional, Transactional and Political Barriers to Competitive Gas Market in Europe: Europe's Pipelines and Economics," Florence School of Regulation Workshop: Tariffs for European Gas Transmission Networks. Florence, Italy, March 6, 2009.

"Cost recovery mechanisms: Options and where each works best; what approach is most likely to get necessary projects built," Law Seminars International, Utility Rate Case: Issues and Strategies 2009. Las Vegas, Nevada, February 5, 2009.

"Alaska as a Gas Supplier: Where is the North Slope Gas Going, and How?" Law Seminars International, Energy in Alaska conference. Anchorage, Alaska, December 8-9, 2008.

"Maintaining Adequate Infrastructure in the Natural Gas and Electric Industries," Increasing Longer-Term Stability in Energy Markets conference sponsored by the Institute for Regulatory Policy Studies. Springfield, Illinois, May 1, 2008.

"Rate Decoupling and Associated Rate and Cost Issues," New Hampshire Public Utilities Commission, Concord, New Hampshire, November 6, 2007.

"Electricity Transmission Cost Allocation in New England: A Throwback to an Earlier Era in Gas Transmission," Law Seminars International, Energy in the Northeast conference, Boston, Massachusetts, October 18-19, 2007.

"Rate Decoupling and Associated Rate and Cost Issues," American Gas Association (AGA) Legal Forum. Vail, Colorado, July 15- 17, 2007.

RECENT SPEECHES (CONTINUED)

"Seeking Competition and Supply Security in Natural Gas: The US Experience and European Challenge," 1st CESSA Conference, Berlin, Germany, May 31-June 1, 2007.

"Toward a Regulatory Equilibrium in Gas Hedging," Electric Utility Consultants' Conference: Utility Hedging in an Era of Natural Gas Price Volatility, Arlington, Virginia, October 4, 2006.

"The Theory of Relationship Specific Investments: Long-Term Contracts and Gas Pipeline Development in the United States." Dresden University of Technology Workshop on Energy Economics and Technology, April 21, 2006.

"A Gas Network to Meet the Needs of New Electricity Generators," Ontario Energy Association, Ontario, Canada, June 23, 2005.

"Forks in the Road for Electricity Transmission," Electricity Industry Regulation and Restructuring conference by The Salt River Project and The Arizona Republic, October 11, 2002.

"Role of Yardsticks in Cost & Service Quality Regulation," London Regulated Industries Group, November 30, 2000.

"Natural Gas Issues: Retail Competition, LDC Gas Rate Unbundling, and Performance Based Rates," Wisconsin Public Utility Institute, November 17, 2000.

"Performance Based Ratemaking (PBR) in Restructured Markets," Edison Electric Institute Seminar in San Antonio Texas, April 27, 2000.

"Benchmarking versus Rate Cases and the Half Live of Regulatory Commitment," Australian Competition & Consumer Commission's Incentive Regulation and Overseas Development Conference, Sydney, Australia, November 19, 1999.

"Benchmarking, Rate Cases and Regulatory Commitment," Australian Competition & Consumer Commission's Incentive Regulation and Overseas Developments Conference, Sydney, Australia, November 14, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications," Energy Week '99, "The Global Shakeout," The World Bank, Washington D.C., April 6-8, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications," Economic Development Institute, The World Bank, Washington D.C., December 8-9, 1998.

"Sustainable Regulation for Russian Oil Pipelines," Presentation at Pipeline Transportation: A Linkage Between Petroleum Production and Consumers, Moscow, June 25, 1997.

"Rocks on the Road to Effective Regulation," Brazil/US Aspen Global Forum, Aspen, Colorado, December 5-8, 1996.

"Stranded Cost Case Studies in the Gas Industry: Promoting Competition Quickly," MCLE Seminar: Retail Utility Deregulation, Boston, MA, June 17, 1996.

"Why Regulate Anyway? The Tough Search for Business-As-Usual Regulation,"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 30, 1996.

"Antitrust for Utilities: Treating Them Just Like Everyone Else"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 29, 1996.

RECENT SPEECHES (CONTINUED)

"Natural Gas Pricing: The First Step in Transforming Natural Gas Industries"—One-Day Interactive Workshop on Pricing Strategy at The Future of Natural Gas in the Mediterranean Conference, Milan, Italy, March 27, 1996.

"Open Access in Gas Transmission," New England Chapter of the International Association for Energy Economics, Boston, Massachusetts, December 13, 1995.

"Light-Handed Regulation for Interstate Gas Pipelines," Twenty-Seventh Annual Institute of Public Utilities Conference, Williamsburg, Virginia, December 12, 1995.

"Ending Cost of Service Ratemaking," Electric Industry Restructuring Roundtable, Boston, Massachusetts, October 2, 1995.

"Promoting Markets for Transmission: Economic Engineering or Genuine Competition?" The Forty-Ninth Annual Meeting of the Federal Energy Bar Association, Inc., May 17, 1995.

"End-Use Competition Between Gas and Electricity: Problems of Considering Gas and Electric Regulatory Reform Separately," ORLANDO '95, The Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, Florida, February 14, 1995.

"Incremental Pricing: Not a Quantum Leap," Natural Gas Ratemaking Strategies Conference, Houston, Texas, February 3, 1995.

"The Feasibility of Competition in the Interstate Pipeline Market," Institute of Public Utilities Twenty-Sixth Annual Conference, Williamsburg, Virginia, December 13, 1994.

"A Mirror on the Evolution of the Gas Industry: The Views from Within the Business and from Abroad," 1994 LDC Meeting-ANR Pipeline Company, October 4, 1994.

"Creating New Markets Out of Old Utility Services," Fifteenth Annual NERA Santa Fe Antitrust and Trade Regulation Seminar, Santa Fe, New Mexico, July 9, 1994.

"Sources of and Prospects for Privatization in Developed and Underdeveloped Economies," Spring Conference of the International Political Economy Concentration and the National Center for International Studies at Columbia University, New York, March 30, 1994.

"Experiencias en el Desarrollo del Mercado de Gas Natural (Experiences in gas market development)," "Perspectivas y Desarrollo de Mercado de Gas Natural," Centro de Extensión de la Pontificia Universidad Católica de Chile, November 16, 1993.

"The Role of Rate of Return Analysis in a More Progressive Regulatory Environment," Twenty-Fifth Financial Forum held by the National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 27, 1993.

"Privatization of Energy and Natural Resources," International Privatization Conference "Practical Issues and Solutions in the New World Order," New York, New York, November 20, 1992.

RECENT INTERNATIONAL REPORTS

"Serious Problems with CREG Document 070 Facing Colombia's Energy Market.", report generated for the Asociación Nacional de Empresas Generadoras (ANDEG). White paper (with Graham Shuttleworth) assessing the economic and policy implications of a proposal by the Colombian Energy and Gas Regulatory Commission (CREG) to reform the country's Reliability Charge mechanism for the wholesale power market. September 2015.

"Principles and Methodology of a Domgas Commercial Price Threshold" Report generated for North West Shelf Joint Venture (NWSJV) to define a methodology for computing a schedule of minimum *reasonable* prices (the Commercial Price Threshold) for prospective gas production for domestic gas (Domgas) based on the NWSJV's supply costs. August 13, 2014.

Gas Pipeline Transport in China: An Economic, Financial and Institutional Analysis," report prepared for Gazprom Export and BP Russian Investments Limited on gas transmission networks and gas pipeline tariffs in China. August 6, 2008.

"Consultation Paper: Development of Approaches Towards Regulating Tariffs for Petroleum Pipelines, Storage and Loading Facilities in South Africa," Report prepared for the National Energy Regulator of South on the determination of economically feasible approaches towards establishing revenue requirements, regulating the setting/approval of tariffs, and developing rules, guidelines and framework regarding regulatory accounts for the petroleum pipelines, storage, and loading facilities in South Africa. December 14, 2006.

"Regulatory Assessment of the Turkish Electricity Sector." Report prepared for Prisma Energy on the examination of the economic and regulatory risks facing investors in the privatization of the energy infrastructure of Turkey. December 6, 2006.

"Calculation of the X-Factor in the 2nd Reference Report of the Bundesnetzagentur." Report prepared for E. ON Ruhrgas, Germany: Design of a regulatory method based on comparison of average tariffs, consistent with new German legislation on the regulation of gas transmission networks. April 21, 2006. (with Graham Shuttleworth and Michael Kraus).

"Cargo Access Charges for the Jorge Chavez International Airport in Lima, Peru." A report prepared for OSITRAN (Public Transport Infrastructure Regulator) on behalf of Lima Airport Partners S.R.L. February 19, 2004.

A Critique of CEPA's Report on "Productivity Improvements in Distribution Network Operators:" A report for EDF Energy (with Graham Shuttleworth). December 16, 2003.

Advised on Fare Regulation Issues related to the Impending Merger of the MTRC and KCRC Railroad Companies in Hong Kong, Mercer Consulting on behalf of MTRC, 2003-2004.

"Natural Gas Pipeline Access Regulation". Report prepared for BHP Petroleum Pty Ltd., May 31, 2001.

"Manual de Procedimientos para el Sistema Uniforme de Cuentas Regulatorias Eléctricas (SUCRE) de México" (April 2000). The report includes an explanation of each of the accounts needed for regulation, recording procedures and the structure the information should take when reporting to the regulator.

"Investigation into Petronets' Liquid Fuels Pipeline Tariffs: Final Report" (March 9th, 2000). This report presents NERA opinions in the quasi-arbitration of the tariffs disputes in the oil industry in South Africa for their liquids pipelines.

"Seeking Genuine Gas Competition in NSW", prepared for BHP Petroleum Pty. Ltd., February 18, 2000.

"Análisis y Revisión del Recurso de Revocatoria Interpuesto por la Compañía Boliviana de Energía S.A. (COBEE) a la Resolución SSDE Nº 92/99 de la Superintendencia de Electricidad" (September 6, 1999). This report represents NERA's opinion on COBEE's appeal in the electricity tariff review process in Bolivia (report in Spanish).

"Gas Sector Regulation Consultancy Services" report prepared for the Vietnam Oil and Gas Corporation, August 10, 1999.

"Natural Gas Demand Estimation for Guatemala, Honduras and El Salvador" (July 19th, 1999). This report done for an international consortium of companies presents calculations of prices and volumes of natural gas demand for three Central American countries if a pipeline is built from Mexico.

"Comments on East Australian Pipeline Limited Access Arrangements: (July 15, 1999). Report prepared on behalf of Incitec Ltd.

"Supplementary Submission to IPART on AGLGN's Proposed Access Arrangements" on behalf of Incitec Limited (April 27th, 1999). This submission discusses reload practices, customer contributions, operating expenses and recalculates charges for a user of the distribution network in New South Wales, Australia.

"Supplementary Submission to IPART on AGLGN's Proposed Costs and Tariffs" on behalf of BHP (April 15th, 1999). This submission explains how NERA recalculated charges for AGLGN in New South Wales, Australia.

"Initial Comments on AGLGN's Revised Access Arrangement Information" on behalf of BHP (March 20th, 1999). This submission presents NERA's comment to AGLGN submission to IPART in New South Wales, Australia.

"International Restructuring Experience" (February 12th, 1999). This paper surveys a number of countries whose experience of restructuring and competition in the electricity sector is directly relevant to the proposed changes in Mexico – Argentina, Australia, Chile, Guatemala, New Zealand, Norway, Spain, the US and the UK

"Report I: Review of the Regulatory Framework" (January 18th, 1999). This report presents the options for a natural gas framework in Peru.

"Conceptual Framework for the Reform of the Electricity Sector in Mexico: White Paper" (November 24th, 1998). This report represents the White Paper for restructuring of the electricity sector in Mexico which is being used in Congress for debate.

"Precios del Gas Natural para la Generación de Electricidad en el Perú" (November 16th, 1998). This report analyzes different alternatives for the treatment of natural gas prices in the electricity tariff model (report in Spanish).

"Tariffs and Subsidies: Report for the Tariffs Group" (November 10th, 1998). This report presents recommendation on the path for tariffs and subsidies for 1999 to the Electricity Tariffs Group of the Government of Mexico.

"Gasoducto México-Guatemala: Informe Final" (October 22nd, 1998). This report analyzes the legal and regulatory framework in both Mexico and Guatemala and costs and volumes for the building of a natural gas pipeline connecting both countries. A copy of the report was given by President Zedillo (Mexico) to President Arzú (Guatemala) (report in Spanish).

"Checks and Balances in Regulating Power Pools: Seven case Studies. A Report for the Electricity Pool of England and Wales" (September 10th, 1998). This report surveys the regulation of power pools in electricity industries around the world.

"Fuels Policy Group: Recommendations" (September 11th, 1998). This report presents recommendations to the Government of Mexico on their fuels policies for the electricity sector.

"Análisis de Costos e Inversiones. Revisión Tarifaria de Transener" (August 25, 1998). Report given to ENRE (the Argentinean electricity regulator) on behalf of a Consortium of Generators on the analysis of costs and investments to be considered for the revenue requirement of the electricity transmission company (report in Spanish).

"Central America Pipeline: Regulatory Analysis and Proposal" (July 28, 1998). This report presents the regulatory analysis and development of a fiscal, legal and commercial framework proposal for gas import, transportation, distribution and marketing in El Salvador, Honduras and Guatemala regarding the proposed Central American Pipeline.

"Energy Regulation in El Salvador" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in El Salvador.

"Energy Regulation in Guatemala" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Guatemala.

"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

"Timetable and Regulatory Review for the Monterrey International Public Tender," (December 5, 1997). A description of the necessary steps to bid for a distribution company as well as an explanation and analysis of natural regulations in Mexico for Pérez Companc.

"Economic Issues in the PFR for 18.3.1(I)(bb) & (cc)", prepared for the New Zealand Treasury, November 17, 1997.

"NERA's Distribution Tariff Model" (October 29, 1997). This report explains the methodology behind NERA's calculations of distribution tariffs for MetroGas.

"Evaluation Design Standards for MetroGas," (October 24, 1997). This report dealt with the analytical support resulting from work with MetroGas to create a meticulously-documented security criterion analysis that supported its efforts to obtain due recognition—and appropriate tariff treatment—for its costs.

"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

"Final Report for Russian Oil Transportation & Export Study: Commercial, Contractual & Regulatory Component," prepared for The World Bank, June 25, 1997.

Response to FIEL's criticisms regarding NERA's report "Cálculo del Factor de Eficiencia (X)" (June 2, 1997).

"Impacts on Pemex of Natural Gas Regulations" prepared for Pemex Gas y Petroquímica Básica México, May 21, 1997.

"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

"New Market Arrangements for the Victorian Gas Industry," prepared for Broken Hill Proprietary Petroleum; March 13, 1997.

"CEG Privatization: Comments to the Regulatory Framework," prepared for Capitaltec Consultoria Economica SA describing our comments with respect to the regulatory framework and the license proposed in the privatization of Riogas and CEG in Rio de Janeiro, Brazil; March 7, 1997.

"Determination of the Efficiency Factor (X)," prepared for ENARGAS, Argentina, January 24, 1997.

"Determination of Costs and Prices for Natural Gas Transmission," prepared for Pemex Gas y Petroquímica Básica, México, December 19, 1996.

"Regulating Argentina's Gas Industry," a report prepared for The Ministry of Economy and The World Bank, November 26, 1996.

"Open Access and Regulation," prepared for Gascor, in the State of Victoria, Australia; (October 2, 1996).

"A Review and Critique of Russian Oil Transportation Tariffs (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 13, 1996.

"Tariff Options for Transneft (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 6, 1996.

"Comments on the Proposed Amendments to the Regulation of Airports in New Zealand," prepared for the New Zealand Parliament Select Committee hearings on the regulation of monopolies, March 13, 1996.

"Evaluating the Shell Camisea Project," prepared for Perupetro S.A., Government of Peru, December 8, 1995.

"Towards a Permanent Pricing and Services Regime," prepared for British Gas, London, England, November, 1995.

"Final Report: Gas Competition in Victoria," prepared for Gas Industry Reform Unit, Office of State Owned Enterprises, June 1995.

"Natural Gas Tariff Study," prepared for the World Bank, May 1995, consisting of:

Principles and Tariffs of Open-Access Gas Transportation and Distribution Tariffs
Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

"Economic Implications of the Proposed Enerco/Capital Merger," prepared for Natural Gas Corporation of New Zealand, December 1994.

"Contract Terms and Prices for Transportation and Distribution of Gas in the United States," prepared for British Gas TransCo, November 1994.

"Economic Issues in Transport Facing British Gas," prepared for British Gas plc, December 1993.

"Overview of Natural Gas Corporation's Open-Access Gas Tariffs and Contract Proposals," prepared for Natural Gas Corporation of New Zealand, October 1993.

Exhibit JDM-2: NERA Report in Alberta Utilities Commission Proceeding 566

December 30, 2010

Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative

NERA
Economic Consulting

Project Team

Jeff D. Makholm, Ph.D.

Agustin J. Ros, Ph.D.

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
617+1 617 927 4500
617 +1 617 927 4501

Contents

List of Tables

List of Figures

I. Introduction

In 2010, the Alberta Utilities Commission ("AUC" or "Commission") launched an initiative to reform rate regulation in Alberta. A component of that reform is to investigate the application of performance-based ratemaking ("PBR") to the regulation of the electric and gas utilities. PBR-based rate regulation—widely applied around the world—is designed to streamline traditional regulatory practices and to encourage regulated businesses to seek more efficient methods of operation. Such regulatory methods rely upon an objective formula by which regulated prices move between base rate cases according to inflation, relative industry productivity and other factors determined by regulators to be important in setting reasonable rates. In the design of objective PBR formulae, it has become customary for regulatory commissions to rely upon an index number reflecting industry productivity over time called Total Factor Productivity ("TFP"), which has widespread support in the theoretical and empirical economic literature. On September 8, 2010 the AUC engaged National Economic Research Associates ("NERA") to conduct a TFP study for use in AUC Proceeding 566 – Rate Regulation Initiative.[1]

This report describes the methodology, data sources and conclusions of our TFP Study ("Study"). We present our qualifications in Section II. After the Executive Summary in Section III, we present in Section IV a description of the requirements of the TFP study specified by the AUC. In Section V, we describe the methodology used to measure TFP as well as discuss several special considerations in this Study. Sections VI and VII describe the sources of data used for the TFP analysis and the steps undertaken to construct the output and input indexes. Section VIII presents our results on relative industry TFP compared to the U.S. and Canadian economy-wide productivity. The methods we use to calculate TFP for PBR plans are well known, and we provide extensive references in our Study to the standard economic literature on the subject.

II. Qualifications

Dr. Jeff D. Makholm is a Senior Vice President in NERA's Boston office and has been at the firm since 1986. He concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers and the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication.

Dr. Makholm is an international expert in the application of price cap regulatory regimes as a variant of traditional cost of service regulation, a subject that draws on his academic work at the University of Wisconsin-Madison (he performed a comprehensive Total Factor Productivity study for electricity companies, using modern index number theory, as his Doctoral Dissertation). On these issues among others, Dr. Makholm has prepared expert evidence, reports

[1] *See*: AUC letter dated September 8, 2010 on Retention of Consultant to Develop a Basic X Factor.

and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies, High Courts and Parliamentary panels in other countries.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. He has represented dozens of gas and electric distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas and electricity producers. Dr. Makholm has also worked with many leading law firms engaged in issues pertaining to the local and interstate regulation of energy utilities. Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal and The Energy Law Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

Dr. Agustin J. Ros is a Vice President in NERA's Boston office and has been at the firm since 1996. Dr. Ros has appeared as an expert witness in telecommunications and energy proceedings and has participated in arbitration proceedings before international regulatory authorities and before the International Chamber of Commerce Arbitration Panel. He has filed expert reports before regulators in the Bahamas, Barbados, Canada, Guatemala, Indonesia, Italy, Mexico, New Zealand, Peru, Singapore, Spain, and Trinidad and Tobago and the United States and has consulted for clients in Brazil, the Cayman Islands, China, the Eastern Caribbean Islands, the Dominican Republic, Panama, and the United Kingdom. Dr. Ros has worked on dozens of price-cap proceedings in the U.S. and internationally, some of which required estimation of the appropriate X-factor to apply in PBR plans.

Dr. Ros started his career as an Executive Assistant to the Chairman of the Illinois Commerce Commission, where he provided expert advice on matters before the Commission. While at the Commission, Dr. Ros worked on the first RPI-X price regulation plan for Illinois Bell Telephone Company in 1994. The work included estimating the industry's total factor productivity and developing the appropriate X-factor to include in the price-cap plan. During his career at NERA, Dr. Ros has worked on numerous X-factor studies in the U.S. and abroad. In the U.S., he has worked on dozens of X-factor calculations and price cap plans both at the Federal and state level, some of which involved estimating total factor productivity. Dr. Ros was the main expert in

2000 and 2004 in the RPI-X price regulation plan for Telefonica de Peru. The work in Peru included estimating total factor productivity and developing the appropriate X-factor. The work undertaken in Peru is summarized in an article he co-authored that was published in the *Journal of Regulatory Economics*, "X-factor Updating and Total Factor Productivity Growth: The Case of Peruvian Telecommunications, 1996-2003." Dr. Ros was also an expert in the price-cap proceedings in Mexico in 1999 and 2004 that established the X-factor offset to apply to Telmex in its price cap plan.

In 2008 Dr. Ros took a two-year leave of absence from NERA to work for the Organization for Economic Cooperation and Development on a competition policy project in Mexico. Working with the Mexican Competition Commission, he co-led a team of competition experts assessing competition in a number of key sectors of the Mexican economy including, airlines, airports, banking, inter-city bus transport, energy, pharmaceutical, retail superstores, and telecommunications. The team made a series of policy recommendations to improve competition, some of which were enacted into law.

Dr. Ros was an Adjunct Instructor at Northeastern University, where he taught a course on the Economics of Regulation and Antitrust, and he has taught antitrust and competition policy at the University of Anahuac in Mexico City. His articles have appeared in book chapters, in peer-reviewed journals such as the *Journal of Regulatory Economics*, *Review of Network Economics* and *Telecommunications Policy*, and in numerous industry and trade journals, such as *Public Utilities Fortnightly* and the *Journal of Project Finance*. He is co-author of the World Bank's InfoDev ICT Regulation Toolkit, a resource aimed at providing regulators with advice on the design of effective and enabling regulatory frameworks within the context of liberalized telecommunications markets. In addition, his research on local competition has been cited in *Business Week,* and in 2001 he published a book on the productivity of employee-owned firms in the U.S. and Brazil.

III. Executive Summary

PBR-based rate regulation arose with both the wave of utility privatizations that began in the United Kingdom in the 1980s and the search around the same time for more effective ways of regulating prices for the rapidly-changing telecommunication industry. A principal focus of PBR regulation is to provide an alternative to traditional cost-based regulation. With their longstanding institutional regulatory histories, traditional regulation in Canada and the United States meant that regulated prices could only normally change as the result of time consuming and disruptive base rate cases where all costs and billing quantities were subject to measurement and update. PBR regulation permits regulated prices to change without a base rate case, lengthening what is known as "regulatory lag." That lengthened regulatory lag subjects regulated utilities to the type of incentives experienced by company managements in competitive industries where benchmark prices move according to the productivity of the industry in question rather than the particular costs of one company.

The extent to which PBR regulation transmits incentives to utility managements is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between base rate cases. Creating an index number for relative industry TFP with those attributes requires a high-quality, transparent and uniform source of data that is readily available to the parties of regulatory proceedings. Such data are collected by the Federal Energy Regulatory Commission ("FERC") for electricity and combination electricity/gas utilities in its "Form 1," which we use as the source of industry empirical data for this Study. We hold objective uniformity in source data for a TFP study to be of paramount importance when such a study is part of regulatory proceedings where the interests of consumers and investors traditionally vie with one another. The FERC Form 1 data is the only source of information that satisfies the criteria of transparency and objectivity for a broad population of industry participants.

We find that during the period 1972 to 2009 the weighted average TFP growth for our population of 72 U.S. electricity and combination electricity/gas companies was **0.85 percent**. During this time period Canadian and U.S. TFP growth averaged approximately **-0.04 percent** and **0.97 percent**, respectively.

IV. Requirements of the Study

As specified by the AUC, a TFP study contributing to a PBR plan must meet six requirements, with which we concur. Those requirements are as follows:

- Be applicable to Alberta gas and electric utilities;
- Compare productivity for gas and electric utilities to economy wide productivity;
- Make the comparison in a transparent manner;
- Use publicly available data;
- Be for use and testing in a regulatory proceeding and for adjusting rates for Alberta electric and gas utilities; and
- Be filed in AUC Proceeding 566 – Rate Regulation Initiative prior to December 31, 2010.

The results of the TFP Study can be used as a transparent and objective basis for adjusting rates for Alberta electricity and gas utilities. Our TFP Study uses a population of 72 U.S. electricity and combination electricity/gas companies from 1972 to 2009.[2] We measure TFP of the distribution component of the electricity business. The population includes companies of different sizes and located in different parts of the United States reflecting a wide diversity of geography, development and age.

We have a deep and longstanding familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective and conclude that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both

---

[2] Appendix I contains a list of the companies used in the study.

the electricity and gas companies in Alberta. We do not conclude that specialized TFP studies for electricity and gas distribution or electricity transmission would be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad array of firms that such studies would require to be a part of transparent and objective PBR plans.

A well-formulated PBR plan measures *relative* long-term industry productivity, *vis-à-vis* the economy as a whole, as a component of approved price movements between base rate cases. In this Study we compare our measure of TFP to the U.S. and Canadian economy-wide TFP.

We conclude that transparency is the *sine qua non* of useful inputs to PBR plans. Thus, we document our methodology and the data used to measure TFP for each step of our analysis. Our calculations and work papers, including any adjustments to the electronic data set (for missing observations or rare but evident data anomalies) are available for inspection and assessment by other parties.

All the data in the Study are both publicly available and of a highly standardized form suitable for a broad-based and objective TFP study. The data used to measure total factor productivity for U.S. standalone electricity as well as combination electricity/gas companies are publicly available from the FERC and other publicly available sources.[3] FERC Form 1 data is filed annually by jurisdictional U.S. standalone electricity and combination electricity/gas companies. The Form 1 provides financial and operational information and can be accessed independently and checked by any interested party.

V. Productivity Methodology and Special Considerations

A. Productivity growth

Productivity growth is specified, by definition, as the *difference* between the *growth rates* of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Thus, the task of productivity measurement involves comparing a firm's outputs and inputs over time. "Total" factor productivity measures all of a firm's inputs and outputs, employing advanced theoretical techniques to combine disparate inputs and outputs into single input and output indexes suitable for comparison to one another.

Because a company produces different types of outputs and uses different types of inputs, a TFP study needs to combine those disparate measures into well defined output and input indexes. Index number theory provides reliable procedures for doing so.[4] In this Study, output, input and

---

[3] In addition to using FERC data, we use data from the U.S. Bureau of Economic Analysis, the U.S. Labor Department, Statistics Canada, the Handy-Whitman Index of Public Utility Construction, and data compiled by the following financial service firms: Standard and Poor's, Bloomberg, Moody's, and Barclays.

[4] *See*: e.g., Caves, D.W., L.R. Christensen, and W.E. Diewert (1982), "The Economic Theory of Index Numbers and the Measurement of Input, Output and Productivity," *Econometrica*, 50:6, pp. 1393-1414.

TFP indexes are constructed using the Tornqvist/Theil index methodology for the various components of outputs and inputs.[5] We create individual TFP indexes and growth rates for each company for each year. We then calculate a weighted average TFP index and growth rate for each year, using the company's total mWh for each year as weights.[6]

TFP measures for this Study span the period 1972 to 2009 with certain data series for capital additions and retirements reaching back to 1964—the earliest date for which electronic Form 1 data was available. Since the rate of growth of TFP is defined as the difference between the growth rates of inputs and outputs, the annual TFP growth for any company is affected by annual changes in inputs (changes in capital investment or labor utilization) and outputs (the introduction of new services or changes in service demand growth). For this reason, TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycle or other idiosyncratic swings inherent to these factors.[7] Major capital replacements, for instance, would have the immediate effect of reducing measured TFP because the investment appears as an unusually large annual capital expenditure without a corresponding change in demand. Over time, however, replacement of the old capital is likely to increase productivity growth because it embodies new technology to serve demand more efficiently. The more years of data that are added, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.

B. Special considerations

Our TFP Study used the FERC cost data directly assigned to the distribution portion of the companies.[8] Costs related to production (generation) and transmission are not included in this Study, nor are costs related to general overheads (*i.e.*, common costs) or customer accounts (e.g., uncollectible accounts).

The data for this Study are electricity data and pertain to electricity companies, whether standalone electricity companies or combination electricity/gas companies. The data used in this

---

[5] *See*: Christensen, L.R., D.W. Jorgenson, and L.J. Lau (1971), "Transcedental Logarithmic Production Frontiers," *Review of Economics and Statistics*, 55:1, pp. 28-45. The authors developed a particular flexible functional form called the "translog". This is a second-order function. The superlative index number that is exact to the translog functional form is the Tornqvist/Theil index.

[6] One use of this approach can be found in the doctoral dissertation of Jeff D. Makholm, "Sources of Total Factor Productivity in the Electricity Industry," 1986 University of Wisconsin-Madison ("Makholm Dissertation").

[7] With approximately 20 data series for 72 companies over 38 years, the database for our Study contains over 50,000 "data points". We reviewed the data to identify any anomalies and determined that some data points were sufficiently extreme to consider replacement. Although in each instance the data point could be traced back to the original FERC data, in 110 cases we decided that the data points were too extreme to be correct. For these data points, we extrapolated from nearby data points to estimate new numbers. Appendix II lists these adjustments.

[8] As discussed in more detail below, one exception to this specification concerns the data series for labor. Because the FERC data provide the total number of employees but do not assign these employees into the various components of service, such as generation, transmission, and distribution, we applied an allocation formula to assign the number of employees to distribution. In addition, we use an allocation formula to determine the net distribution plant in service in 1964, as set out below.

Study do not include data for standalone gas utilities. We are not aware of a readily-available data source that would permit a comparably transparent TFP study for standalone gas utilities.

There is evidence that productivity of gas and electricity companies are similar. Both electricity and natural gas distribution are highly capital intensive. In some instances, the electricity and gas distribution facilities share the same support structure. According to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 percent (using gross output as the output measure) while for natural gas distribution, water and other systems TFP growth was 0.21 percent (using gross output as the output measure).[9] Using value added as the measure of output, the numbers are 0.37 percent for electric power generation, transmission and distribution companies and 0.34 percent for natural gas distribution, water and other systems.[10]

VI. Methodology - Output Index

Growth in a firm's productivity is measured by the difference between the growth rate of the firm's outputs and the growth rate of the firm's inputs.[11] To create the output index we obtain data on the outputs that the companies produce. Since standalone electricity and combination electricity/gas companies produce several outputs, we also need to determine the weights (shares) that are applied to each type of output in order to determine one overall output index.

A. Output quantity

The output measure that we use in this Study is sales volume (mWh). We combine sales volume for several different types of customers to create the output index. The different categories of sales volumes used in this Study and the accompanying FERC account information are:

1. Residential Electric Sales Volume;[12]

2. Small (Commercial) Electric Sales Volume;[13]

3. Large (Industrial) Electric Sales Volume;[14] and

[9] *See*: Statistics Canada, Table 383-0022, Multiproductivity based on gross output; electric power generation, transmission and distribution; Multiproductivity based on gross output; natural gas distribution, water and other systems. A statistical "t-test" rejected the hypothesis that there was a statistically significant difference in the two series. All data are available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html.

[10] *See*: Statistics Canada, Table 383-0022, Multiproductivity based on value added; electric power generation, transmission and distribution; and Multiproductivity based on value added; natural gas distribution, water and other systems. A statistical "t-test" rejected the hypothesis that there was a statistically significant difference in the two series. All data are available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html.

[11] *See*: Caves, Christensen and Diewert (1982) *op. cit.* footnote 4.

[12] Electric Operating Revenues: Residential Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 2, Column d.

[13] Electric Operating Revenues: Small or Commercial Electric Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 4, Column d.

4. Total Public Street, Other, Railroad Sales Volume.[15]

Based upon these data, we create an index for each of the first four categories (residential, commercial, industrial, and public).[16]

B. Output shares

Because we have separate indexes for each of the sales volume categories (*i.e.*, residential, commercial, industrial, and public) we need weights (shares) in order to determine one overall output index. In this Study, we use electric sales ($) for each of the categories (*i.e.*, residential, commercial, industrial, and public) to construct the shares. Specifically, the different categories of sales used in this Study and the accompanying FERC account information are:

1. Residential Electric Sales;[17]

2. Small (or Commercial) Electric Sales;[18]

3. Large (or Industrial) Electric Sale;[19] and

4. Total Public Street, Other, Railroad Sales.[20]

The weight for the output category residential sales volume is the ratio of residential electric sales to the summation of categories (1) – (4) (residential sales, commercial sales, industrial sales and public sales). The same applies for determining the weights for commercial, industrial, and public sales. The output index is then determined using the Tornqvist/Theil methodology.

VII. Methodology – Input Index

To create the input quantity index, we need to measure the growth of three separate inputs (labor, capital and materials, rents and services[21]) and aggregate the three separate inputs into an overall

---

[14] Electric Operating Revenues: Large or Industrial Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 5, Column d.

[15] Electric Operating Revenues: Public Street and Highway Lighting, Other Sales to Public Authorities, and Sales to Railroad and Railways: Megawatt Hours Sold. FORM 1: Page 301.

[16] The comparison base for this index (and all the indexes and calculations in this study) is Duquesne Light Company (1980). That is, the comparison base in the Tornqvist/Theil indexing methodology is Duquesne Light (1980) and all indexes in this study are normalized by the value of that company in that year. Selection of the comparison base is arbitrary and selecting a different company and/or year would not materially affect the results for TFP growth. *See*: Makholm Dissertation *op. cit* footnote 6.

[17] Electric Operating Revenues: Residential Sales. FERC FORM 1: Page 300, Line 2, Column b.

[18] Electric Operating Revenues: Small or Commercial Electric Sales. FERC FORM 1: Page 300, Line 4, Column b.

[19] Electric Operating Revenues: Large or Industrial Sales. FERC FORM 1: Page 300, Line 5, Column b.

[20] Electric Operating Revenues: Public Street and Highway Lighting, Other Sales to Public Authorities, and Sales to Railroad and Railways. FORM 1: Page 300.

input index using weights (shares). Some of the components to create the input quantity index are also used to create an input price index that measures how input prices have changed during the relevant time period. In this section we discuss the methodology used for each input.

A. Labor

1. Labor quantity

For labor quantity we use number of employees. Specifically, we use the number of full-time employees and add 50 percent of part-time and temporary employees to obtain the number of full-time equivalents ("FTEs"). The FERC Form 1 does not contain employment data separated into the different components, including generation, transmission, and distribution. Therefore, we used the following formula to assign the FTEs to distribution:

$$FTEs\ Distribution = (FTEs)\times\left(\frac{Direct\ Payroll\ to\ Electric\ Distribution}{Total\ Electric\ Salary\ \&\ Wages}\right).$$

The FERC accounts that we use to create the labor quantity index are:

1. Total Regular Full-Time Employees;[22]
2. Total Part-Time and Temporary Employees;[23]
3. Direct Payroll to Electric Distribution;[24] and
4. Total Electric Salaries & Wages.[25]

Beginning in 2002, the FERC Form 1 no longer contains employee data. To account for this change, we estimated the number of employees by using the previous years' electric distribution payroll growth rate for the years 2002 to 2009.[26] Based upon these data, we create a labor quantity index.[27]

---

[21] In a TFP study, the materials, rents and services category ("MRS") is also known as the "all others" category.

[22] Total Regular Full-Tim Employees: FERC FORM 1: Page 323, Line 2 (1972-2001).

[23] Total Part-Time Employees: FERC FORM 1: Page 323, Line 3 (1972-2001).

[24] Direct Payroll: Electric Distribution Operation and Maintenance. FERC FORM 1: Page 354, Line 23, Column b.

[25] Total Electric Operation and Maintenance Salaries and Wages: FERC FORM 1: Page 354, Line 28, Column d.

[26] For the missing years of employment data, we took the previous year's growth rate in the account direct payroll electric distribution and applied that growth rate to the previous year's employees.

[27] *See*: footnote 16.

2. Labor share

In order to obtain an aggregate input index made up of the labor, capital and materials, rents and services indexes we must use weights (shares). For labor, we use the FERC account Direct Payroll to Electric Distribution.

3. Labor price

The price of labor is calculated by dividing Direct Payroll to Electric Distribution by FTEs Distribution. We construct a labor price index that is then combined with the capital and material rents and services price index to construct an overall input price index.

B. Materials, Rents and Services ("All Others")

1. MRS quantity

Materials, rents and services are an important input into a company's production process. To calculate the MRS quantity, we follow a two-step process. The first step is to obtain MRS expenses. The second step is to deflate the MRS expense by a price index.

With respect to the first step, we calculate the MRS expense as the difference between operating expenses and labor expenses. Specifically, we subtract Direct Payroll to Electric Distribution (used above in determining labor input) from Total Distribution Operation and Maintenance Expenses (Distribution O&M). Salary and wages are a component of Distribution O&M and need to be removed. Depreciation and amortization are not a component in the FERC Distribution O&M account.

With respect to the second step, we divide the MRS expense by the Gross Domestic Product Price Index to obtain a measure of the MRS quantity input.

We use the following data from FERC and the U.S. Bureau of Economic Analysis to create a material, rents and services index:[28]

1. Total Distribution Operations and Maintenance Expenses;[29] and

2. U.S. Gross Domestic Product Price Index.[30]

2. MRS share

We use weights (shares) in order to obtain an aggregate input index made up of labor, capital and materials, rents and services indexes. The MRS expense is used as the weight (share).

---

[28] *See*: footnote 16.

[29] Total Distribution Operation and Maintenance Expenses: FERC FORM 1: Page 322, Line 156, Column b.

[30] Bureau of Economic Analysis, National Income Product Accounts (NIPA) Table 1.1.4 using 1987 as base year.

3. MRS price

For the price of MRS, we use the U.S. GDP-PI.

C. Capital

Unlike labor services, which are rented on an ongoing basis at a relatively easily quantifiable price, capital equipment rental prices must be imputed because capital is purchased in one time period but delivers a flow of service over many subsequent time periods.

In addition, the "stock" of capital at any one point in time must be calculated in a way that permits comparisons across time. This is due to the fact that the "value" of the capital stock is affected by many variables. First, at any point in time there are varying vintages of capital that a company uses, some purchased recently and others that have been in use for much longer periods of time. The existence of heterogeneous types of plant and equipment[31] and the simultaneous use of capital of varying vintages at different stages of depreciation requires a method of comparison. Second, besides the initial purchase price, other variables affect the value of the capital stock, such as tax laws, depreciation, interest rates, and the differences between accounting and economic cost.

To measure the economic value of such assets, we must: (1) account for the loss of economic value represented by depreciation; and (2) adjust for changes in plant construction prices over time. A measure of the capital stock that meets these requirements is the "replacement cost of plant" expressed in constant dollars, as discussed below.

1. Capital quantity

For the capital quantity, we measure the replacement cost of distribution plant expressed in constant dollars. One common method of measuring the replacement cost of distribution plant expressed in constant dollars is the perpetual inventory method which accounts for the presence of different vintages of capital stock at any given point in time.[32]

The first year of our data sample (1972) is the base year. The first year for which capital information is available (1964) is the benchmark year. From the benchmark year forward, we adjust capital stock annually to reflect actual capital stock additions and actual capital stock retirements.[33] In the benchmark year (1964), there is capital of varying vintages in place. Because the vintages of this capital stock are not known to us, we must approximate them.[34] By

---

[31] Plant and equipment is a common term used to denote a firm's capital assets.

[32] L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

[33] We use a "one-hoss shay" depreciation pattern specification for capital—*i.e.*, where the flow of services received from capital is constant at full productive efficiency up until its retirement.

[34] If we could track the data back to the company's inception, we would have a full set of additions and retirements and not need to estimate the benchmark year. However, since that data is not available we trace the data back as far as we can and work with what is available.

allowing the benchmark year (*i.e.*, the first year for which we have capital data) to predate the base year (*i.e.*, the first year of the data sample to be used for TFP calculations), the effect of this approximation is mitigated.

For the benchmark year, we compute capital quantity from the Handy-Whitman Index of Public Utility Construction ("HW"),[35] which provides asset price indexes and the capital book value in the benchmark year. The Handy-Whitman Index numbers furnish a yardstick for fluctuations in the value of property, reflecting constant dollar reproduction costs. Average prices and cost trends are used to develop the Handy-Whitman Index. The Handy-Whitman Index is commonly used by utilities and regulators in their calculations of rate base for rate cases and in their valuations of property for insurance purposes.

The formula for calculating the value of the distribution capital stock in the benchmark year is:

$$K_{benchmark} = \frac{book\ value\ of\ utility\ plant\ in\ benchmark\ year}{\sum_{1}^{20} i\left[\frac{i}{\sum_{i=1}^{20} i}\right] HW_{1944+i}} .$$

Capital quantities after the benchmark year are given by:

$$K_t = K_{t-1} + \frac{gross\ additions\ to\ plant_t}{HW_t} - \frac{retirements_t}{HW_{t-s}} ,$$

where *s* is the depreciable service life of the asset.

The equation above lists two different indexes—one for additions and one for retirements. In the FERC Uniform System of Accounts, additions are added in current dollars, and retirements are subtracted according to their original dollars.

The FERC accounts that are used to create the capital quantity index are:

1. Total Distribution Plant: Additions;[36]

2. Total Distribution Plant: Retirements;[37]

3. Production Plant in Service;[38]

[35] The Handy-Whitman Index is prepared especially for electric, gas, and water utilities and it is the only known publication of its kind. The electric and gas groups are arranged according to the FERC Uniform System of Accounts.

[36] Total Distribution Plant: Additions. FERC FORM 1: Page 206, Line 75, Column c.

[37] Total Distribution Plant: Retirements. FERC FORM 1: Page 207, Line 75, Column d.

4. Transmission Plant in Service;[39]

5. Distribution Plant in Service;[40]

6. General Plant in Service;[41] and

7. Net Plant in Service.[42]

We also use the Handy-Whitman Index of Public Utility Construction for electric utilities. The Handy-Whitman Index provides an index number for six regions for the U.S. for every year dating back to 1912, including an index number for Total Distribution Plant. The index uses 1973 as its base year.[43]

Data on production, transmission, general and net plant in service is required in order to determine the net distribution plant in service for the benchmark year (1964). The FERC account for distribution plant in service is for the gross (total) book value of distribution plant while for the benchmark year we require net distribution plant in service. The following methodology is used to obtain net distribution plant in service for the benchmark year (1964):

$$Net\ Distribution\ Plant = \frac{(Net\ Plant\ in\ Service) \times (Distribution\ Plant\ in\ Service)}{(Production + Transmission + Distribution + General\ Plant\ in\ Service)}.$$

Using these data, we create a capital quantity index.[44]

2. Capital share

In order to obtain an aggregate input index made up of the labor, capital and materials, rents and services indexes we use weights (shares). For capital, the share used is the capital quantity described above multiplied by the price of capital. Our methodology for determining the price of capital is discussed in the next subsection.

---

[38] Total Production Plant in Service: End Year Balance. FERC FORM 1: Page 205, Line 46, Column g (1964).

[39] Total Transmission Plant in Service: End Year Balance. FERC FORM 1: Page 207, Line 58, Column g (1964).

[40] Total Distribution Plant in Service: End Year Balance. FERC FORM 1: Page 207, Line 75, Column g (1964).

[41] Total General Plant: End Year Balance. FERC FORM 1: Page 207, Line 99, Column g (1964).

[42] Net Electric Utility Plant in Service: FERC FORM 1: Page 200, Line 15, Column c (1964).

[43] For the last ten years, the Handy-Whitman data uses two index numbers for each year, one for January 1st and the other for July 1st, rather than an annual number. To convert these two numbers into one annual number, we examined the formula Handy-Whitman used for years prior to 2001 and found the following calculation to transform the two six-month numbers into an annual figure: $HW_t = (HW_{Jan\ 1,t} \text{ x } 2(HW_{Jul\ 1,\ t}) \text{ x } HW_{Jan\ 1,\ t+1})/4$. We calculated an annual number for 2001-2009 using this formula. In addition, the Handy-Whitman data is divided into six regions: North Atlantic, South Atlantic, North Central, South Central, Plateau, and Pacific. We cross-referenced the states in each of these six regions with the state in which each operating company is located to find the applicable index number.

[44] *See*: footnote 16.

3. Capital price

Capital service prices are based on the relationship between the acquisition price of new capital goods and the present value of all future services from these goods. To calculate the price of capital we use the following formula based upon Christensen and Jorgenson (1969):[45]

$$P_{k,t} = \left(\frac{1-k-uz}{1-u}\right)(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^{s}\right]^{-1} HW_{t-1}\,.$$

where:

1. k = the investment tax credit rate;
2. u = the corporate profits tax rate;
3. z = the present value of the depreciation deduction on new investment;
4. r = the cost of capital;
5. i = the expected inflation rate over the lifetime of the assets;
6. s = asset lifetime; and
7. HW_{t-1} = Handy-Whitman's asset price in the prior year.

For *k*, there has been no general investment tax credit for over twenty years.[46] For *u*, the corporate profits tax rate, we obtained information using Form 1120 on the IRS website.[47]

The present value of future depreciation deductions on new investment, *z*, is a function of the tax depreciation method used, the asset tax lifetime, and the rate of return. The distinction in asset lives is drawn because depreciation for tax purposes is frequently allowed to take place over a much shorter time span (e.g., five years, or the "sum of the years' digits" method[48]) than is allowed for ratemaking purposes. Using the sum of the years' digits method, *z* then becomes:

$$z = \frac{2}{RT}\left[1-\left[\frac{(1+R)}{R(T+1)}\right]\left[1-\left(\frac{1}{(1+R)}\right)^{T+1}\right]\right],$$

[45] *Op. cit.* footnote 32.

[46] The list of all business tax credits can be found at the IRS website for small businesses: http://www.irs.gov/businesses/small/article/0,,id=99839,00.html, accessed on December 12, 2010.

[47] *See*: IRS publication, "Instructions for Forms 1120 and 1120-A" for each year, available at http://www.irs.gov/app/picklist/list/priorFormPublication.html, accessed on December 30, 2010.

[48] The sum of the years' digits method is one form of accelerated depreciation. We assign a number to each year of the asset's useful life, starting with 1 for the first year, etc. These numbers are added to get their sum, i.e., n(n+1)/2. A separate depreciation rate is then calculated for each year, with the number assignments being reversed. For example, with a 12-year asset life, the sum of the digits is 78. Depreciation in year 1 is then 12/78.

where R is the rate of return for discounting depreciation deductions and T is the tax lifetime of the asset. In this Study we use a value of 0.511.[49]

To calculate r, the cost of capital, we used the bond yields of the company's debt. We obtained monthly long-term bond ratings from Standard & Poor's ("S&P") Ratings Direct for each of the companies.[50] We then downloaded S&P's and Moody's monthly utility bond yields from Bloomberg for Aaa, Aa, A, and Baa ratings.[51]

To find i, the expected inflation rate over the lifetime of the assets, we obtained data on the Daily Treasury Yield Curve Rates for 30-year bonds from the U.S. Treasury website and averaged them to arrive at a Yearly Treasury Yield Rate (Risk-Free Return).[52] To find the Risk-Free Return Net of Inflation, we downloaded the Consumer Price Index from the Bureau of Labor Statistics and subtracted it from the Yearly Treasury Yield Rate for each year from 1972-2009.[53] We then averaged this differenced to arrive at the Risk-Free Return Net of Inflation for the period 1972-2009. To find the Expected Long Term Inflation Rate for each year, we subtracted the Risk-Free Return Net of Inflation from the Yearly Treasury Yield Rate.

For s, the asset lifetime, we use 33 years. HW_{t-1} refers to the same Handy-Whitman Total Distribution Plant asset price index number as that used to calculate the capital index.

[49] *See*: Makholm Dissertation *op. cit* footnote 6. Christensen and Jorgenson (1969), *op. cit*. footnote 32, and Gollop and Jorgenson, "U.S. Productivity Growth by Industry, 1947-1973," Discussion Paper 7712, Social Systems Research Institute, University of Wisconsin, Madison, September (1977), use a value of R (the rate of return for discounting depreciation deductions) of 0.10. M. Sing (Doctoral Thesis University of Wisconsin 1984), employs a value of T (the tax lifetime of the asset) of 23 years on electric plants. These values give a value of z of 0.511.

[50] Because S&P did not have a ratings history for Commonwealth Electric, one of the companies that was consolidated into NSTAR, we found the rating history for that company on Bloomberg.

[51] Because Moody's does not provide yields for anything lower than the Baa rating, we downloaded Fair Value daily utility bond yields from Bloomberg for the Ba rating. We also downloaded monthly (non-utility specific) junk bond yields from Barclays for the B and D ratings, both of which are non-investment grade. In some instances, the company's rating was between the ratings provided by Moody's, such as an A1 rating. In these cases we rounded to the nearest available rating and used the yield for that rating.

[52] The Daily Treasury Yield Curve Rates for 30-year bonds were discontinued between February 2002 and February 2006. For this time period, the U.S. Treasury published Daily Treasury Yield Curve Rates for 20-year bonds as well as an "extrapolation factor," which was designed to be added to the 20-year yield curve rates to estimate 30-year yield curve rates. We therefore used the 20-year yield curve rates plus the extrapolation factor as a substitute for the 30-year yield curve rates between February 2002 and February 2006.

[53] Bureau of Labor Statistics, available at: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt, accessed on December 30, 2010.

VIII. Results

In this section we present our results for output, inputs and TFP growth.

A. Output Index

Table 1 summarizes the average output shares and the average output index growth by type of service during the period 1972 to 2009. Residential service comprised the largest component of the firms' output, followed by commercial, industrial and the public category. The fastest growing output measure was commercial, followed by residential, industrial and the public category.

Table 1. Output shares and output index growth, 1972-2009[54]

Service	Share of Output	Output Index Growth Rate
	------------------------(percent)	---------------------------
Residential	41.27	2.54
Commercial	34.95	3.68
Industrial	20.51	1.41
Public	3.26	1.31

Figure 1 in Appendix III depicts the output shares from 1972 to 2009 while Figure 2 through Figure 5 depict the growth rates for the different outputs during the same period. Figure 1 shows that residential and commercial shares increased slightly during the period while the share of industrial output declined, beginning in the mid 1980s. The share for public remained fairly constant at about three percent over the period.

Residential output growth during the period averaged 2.54 percent and was the least volatile (standard deviation of 2.77 percent) of the four output measures during the period (see Figure 2). Most of the growth was positive, with the exception of six years, three of which occurred after 2005. The year with the fastest growth was 1973, at 8.00 percent, and the year with the slowest growth was 1992, when the residential output index fell by 2.92 percent.

Commercial output growth during the period averaged 3.68 percent and was the second least volatile output series with a standard deviation of 2.88 percent (see Figure 3). There were only three years of negative growth for commercial output, two of which occurred in 2008 and 2009. The year with the fastest growth was 1988, at 10.31 percent, and 2009 was the year with the slowest growth, -4.00 percent.

Industrial output growth during the period averaged 1.41 percent and was the most volatile output series with a standard deviation of 3.69 percent (see Figure 4). There were 12 years of

[54] Source: NERA TFP Study, share of output and growth rates are unweighted.

negative growth during the period. The year with the fastest growth was 1976, at 10.73 percent. The year with the slowest growth was 1982, at -7.18 percent.

Finally, public output growth during the period averaged 1.31 percent, the output measure with the slowest growth rate and the second most volatile output series with a standard deviation of 3.20 percent (see Figure 5). There were 10 years of negative growth and the year with the fastest growth rate was 2003, at 14.20 percent. The year of slowest growth was 2005, at -3.76 percent.

B. Input Index

Table 2 summarizes the average input shares and the average input growth rate by the type of input during the period 1972 to 2009. Capital accounted for the largest share of the companies' inputs at a little over 63 percent, followed by labor at 18.6 percent and MRS at 17.8 percent. Labor was the slowest-growing input, followed by capital and MRS.

Table 2. Input shares and input index growth, 1972-2009[55]

Input	Share	Input Index Growth Rate
	------------------------(percent)------------------------	
Labor	18.58	1.16
MRS	17.80	4.17
Capital	63.62	1.32

Figure 6 depicts the input shares during the period 1972 to 2009 while Figure 7 through Figure 9 depict the growth rate of the inputs during the same period. The share of capital increased during the period from 60 percent in 1972 to 73 percent in 2009. Labor decreased from 23 percent in 1972 to 12 percent in 2009 while MRS increased slightly initially and then decreased in the later years.

Labor input growth during the period averaged 1.16 percent with a standard deviation of 4.95 percent, the most volatile input series. MRS input growth during the period averaged 4.17 percent with a standard deviation of 4.49 percent. Capital input growth during the period averaged 1.32 percent with a standard deviation of 0.61 percent, the least volatile input series.

C. TFP Growth

Table 3 summarizes output, input and TFP growth for each year. Figure 10 in Appendix III depicts the yearly TFP growth rates. The weighted average TFP growth for our population of companies is 0.85 percent. Figure 10 depicts a TFP growth that fluctuates considerably year to year and that in more recent years exhibits sharp declines. The fastest TFP growth occurred in 1976 at 4.96 percent while the slowest TFP growth occurred in 2008 at -5.26 percent.

---

[55] Source: NERA TFP Study, share of input and growth rates are unweighted.

Table 3. Output, input and TFP growth, 1973-2009[56]

Year	Output growth	Input growth	TFP growth
	(percent)		
1973	7.59	2.88	4.72
1974	-0.50	0.05	-0.55
1975	2.32	-2.23	4.55
1976	5.12	0.16	4.96
1977	4.38	1.67	2.71
1978	3.52	2.35	1.17
1979	2.87	1.31	1.56
1980	1.39	2.19	-0.79
1981	1.05	0.60	0.45
1982	-1.03	2.53	-3.57
1983	2.91	1.96	0.95
1984	4.59	1.78	2.80
1985	1.87	2.08	-0.20
1986	2.77	0.37	2.40
1987	4.11	1.81	2.30
1988	5.07	-0.04	5.11
1989	2.18	1.43	0.75
1990	1.70	0.70	1.00
1991	2.33	1.82	0.51
1992	-0.64	-0.81	0.17
1993	4.20	1.21	2.99
1994	2.27	0.37	1.90
1995	2.74	-1.20	3.95
1996	2.01	0.39	1.62
1997	1.12	0.52	0.60
1998	3.15	2.62	0.53
1999	1.72	1.82	-0.10
2000	3.13	1.02	2.12
2001	-1.02	2.39	-3.41
2002	3.09	2.66	0.43
2003	0.66	3.53	-2.87
2004	2.00	-0.29	2.29
2005	2.94	1.28	1.66
2006	-0.24	2.69	-2.92
2007	2.33	2.28	0.05
2008	-1.84	3.43	-5.26
2009	-3.92	-1.01	-2.91
Average	2.11	1.25	0.85

[56] Note: Output, input and TFP growth in each year are weighted by total mWh. Source: NERA TFP Study.

D. Economy-wide TFP

We have been asked to compare our Study TFP growth to economy-wide productivity. Canadian TFP growth during the 1972 to 2009 period has averaged -0.04 percent. During the same time period U.S. TFP growth has averaged 0.91 percent. Table 4 summarizes the yearly TFP growth rates for the U.S. and Canadian economy *vis-à-vis* the TFP growth rates in our Study. Figure 11 and Figure 12 compare our Study TFP growth to the TFP growth for the Canadian and U.S. economies, respectively.

Table 4. Study TFP growth and U.S. and Canadian economy TFP growth, 1973-2009[57]

Year	Study TFP Growth	U.S. TFP Growth	Canadian TFP Growth
	(percent)		
1973	4.72	2.80	0.73
1974	-0.55	-3.40	-1.56
1975	4.55	1.20	-1.37
1976	4.96	3.60	3.97
1977	2.71	1.60	1.55
1978	1.17	1.30	-0.10
1979	1.56	-0.30	-1.63
1980	-0.79	-2.20	-2.38
1981	0.45	0.30	-0.32
1982	-3.57	-3.20	-1.91
1983	0.95	2.90	1.41
1984	2.80	3.00	3.31
1985	-0.20	1.30	1.24
1986	2.40	1.70	-1.53
1987	2.30	0.40	-0.10
1988	5.11	0.80	0.10
1989	0.75	0.30	-1.24
1990	1.00	0.70	-1.78
1991	0.51	-0.90	-2.78
1992	0.17	2.50	0.55
1993	2.99	0.20	0.98
1994	1.90	0.70	2.38
1995	3.95	-0.30	0.21
1996	1.62	1.70	-0.95
1997	0.60	0.80	1.17
1998	0.53	1.50	0.74
1999	-0.10	1.80	1.99
2000	2.12	1.70	2.25
2001	-3.41	0.80	-0.30
2002	0.43	2.40	0.50
2003	-2.87	2.60	-0.50
2004	2.29	2.60	-0.70
2005	1.66	1.00	0.20
2006	-2.92	0.50	-0.71
2007	0.05	0.50	-0.61
2008	-5.26	0.10	-2.25
2009	-2.91	0.80	-2.20
Average	0.85	0.91	-0.04

[57] Source: TFP growth: NERA TFP Study, Table 3 above; U.S. TFP growth: U.S. Bureau of Labor Statistics, Historical Multifactor Productivity Measure, Table PG 4c available at: http://www.bls.gov/mfp/mprdload.htm, accessed on December 30, 2010, data for 2009 is preliminary; Canadian TFP growth: Statistics Canada, Table 383-0021, Multifactor productivity in the aggregate business sector and major sub-sectors; Canada; Multifactor productivity; Business sector (index, 2002=100) available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

E. Input price growth

We also measured the input price growth during the period 1972 to 2009 and compared it to the input price growth of the Canadian and U.S. economy, respectively. Table 5 summarizes the results.

Input prices in our TFP Study grew at an annual rate of 5.61 percent compared to input price growth for the Canadian and U.S. economy of 4.46 percent and 4.84 percent, respectively. Figure 13 compares our Study input price growth to the input price growth for the Canadian economy during the same period while Figure 14 compares our Study input price growth to the input price growth for the U.S. economy during the same period.

We conducted a statistical test to test the hypothesis that there was a statistically significant difference in the input price growth series for our Study and the input price growth series for the Canadian and U.S. economy. Specifically, we estimated the probability associated with a Student's t-test and rejected the hypothesis that there was a statistically significant difference in the input price growth series for our Study and the input price growth series for the Canadian and U.S. economy.

Table 5. Study input price growth and U.S. and Canadian economy input price growth, 1973-2009[58]

Year	Input price growth[(1)]	U.S. input price growth	Canadian input price growth
	-------(percent)-------		
1973	3.03	8.35	10.40
1974	8.19	5.68	13.76
1975	19.55	10.65	9.26
1976	12.51	9.34	13.58
1977	-0.35	7.97	8.12
1978	6.52	8.32	6.58
1979	11.20	8.02	8.49
1980	13.82	6.92	7.69
1981	11.90	9.67	10.42
1982	4.08	2.90	6.53
1983	1.49	6.85	6.87
1984	5.29	6.76	6.61
1985	1.13	4.33	4.28
1986	9.75	3.91	1.57
1987	3.73	3.30	4.47
1988	-2.77	4.23	4.62
1989	5.94	4.08	3.21
1990	3.53	4.56	1.47
1991	2.38	2.64	0.13
1992	2.45	4.87	1.85
1993	5.84	2.41	2.50
1994	-0.68	2.81	3.53
1995	5.02	1.78	2.48
1996	0.16	3.60	0.60
1997	2.00	2.57	2.48
1998	5.22	2.63	0.20
1999	5.36	3.27	3.72
2000	0.31	3.87	6.41
2001	11.96	3.06	0.82
2002	11.96	4.02	1.61
2003	-6.16	4.75	2.80
2004	-4.41	5.44	2.49
2005	4.46	4.34	3.49
2006	6.10	3.76	1.93
2007	8.36	3.44	2.58
2008	20.60	2.29	1.86
2009	8.12	1.72	-4.34
Average	5.61	4.84	4.46

[58] Note: [(1)] Input price growth is weighted by total mWh. Input price growth for U.S. and Canadian economy are derived from: Economy-wide input price growth = GDP-PI growth + economy-wide TFP growth. Source: Input price growth: NERA; U.S. GDP-PI: Bureau of Economic Analysis, Table 1.1.9, *Implicit Price Deflators for Gross Domestic Product*, available at: http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=N, accessed on December 30, 2010; Canadian GDP-PI: Statistics Canada, Table 380-0056, *Implicit Chain Price Index Gross Domestic Product*, available for a fee at http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

IX. APPENDIX I. List of companies used in the Study

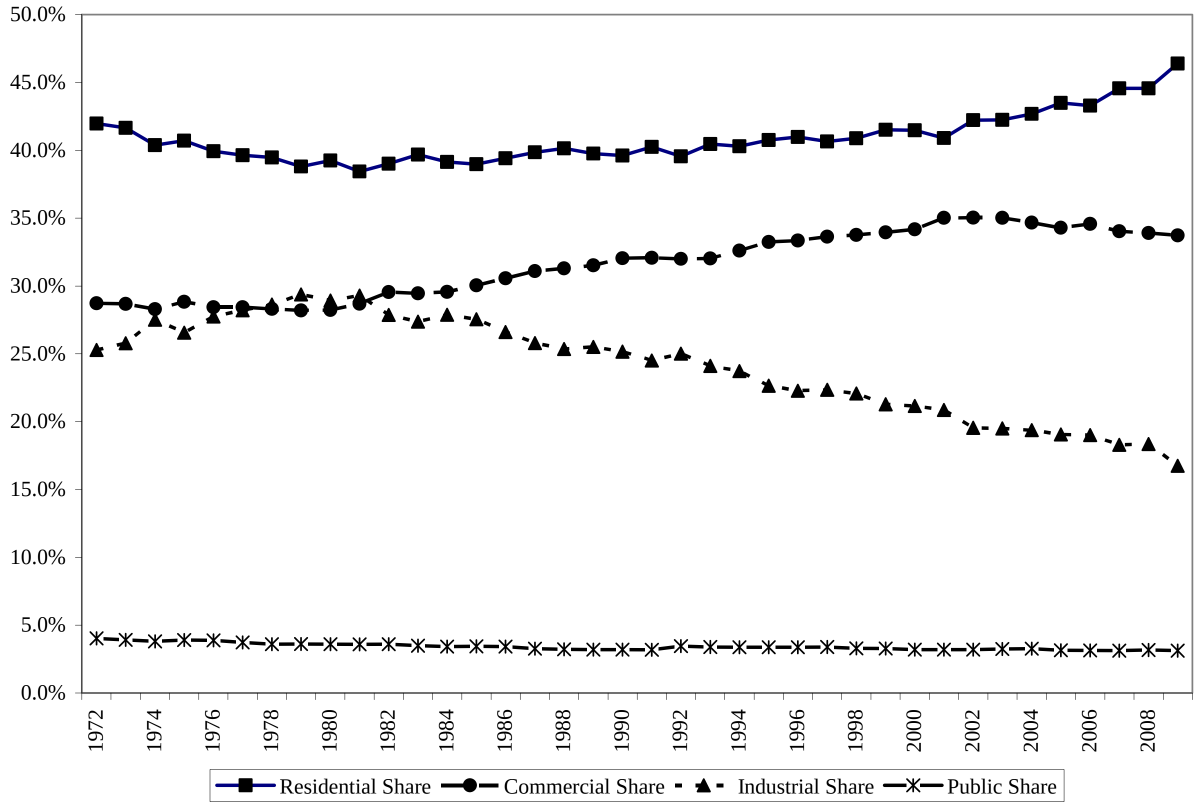
Alabama Power Company
Appalachian Power Company
Arizona Public Service Company
Baltimore Gas and Electric Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corp
Central Illinois Light Company
Central Vermont Public Service Corporation
Cleveland Electric Illuminating Company
Columbus Southern Power Company
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
Detroit Edison Company
Duke Energy Indiana, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, L.L.C.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Florida Power Corporation
Green Mountain Power Corporation
Gulf Power Company
Idaho Power Company
Illinois Power Company
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Utilities Company
Madison Gas and Electric Company
Massachusetts Electric Company
MDU Resources Group, Inc.
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company
Narragansett Electric Company
Nevada Power Company
New York State Electric & Gas Corp
Niagara Mohawk Power Corporation
Northern Indiana Public Service Co.
NSTAR
Ohio Edison Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.
Otter Tail Corporation
Pacific Gas and Electric Company
PECO Energy Company
Pennsylvania Electric Company
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Puget Sound Power and Light Company
South Carolina Electric & Gas Co.
Southern California Edison Co.
Southern Indiana Gas and Elec. Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Tucson Electric Power Company
Virginia Electric and Power Company
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Wisconsin Public Service Corp

X. APPENDIX II. List of changes made to original FERC data

Company Name	Year(s)	Variable(s) Changed	Methodology
Appalachian Power Company	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate.
Central Illinois Light Company	2002	DWGSAL, TWGSAL, ADD, & RET	Averaged respective 2001 & 2003 values.
Cleveland Electric Illuminating Company	1975	TWGSAL	Averaged 1974 & 1976 values.
Consolidated Edison Company of New York, Inc.	2002-2009	DWGSAL	Extrapolated forwards using TWGSAL growth rates.
Consolidated Edison Company of New York, Inc.	1983	DWGSAL	Averaged 1982 & 1984 values.
Consumers Energy Company	2002-2005	DWGSAL, TWGSAL, ADD, RET, & O&M	Averaged respective 2001 & 2006 values.
Consumers Energy Company	1993	DWGSAL & TWGSAL	Averaged respective 1992 & 1994 values.
Delmarva Power & Light Company	1979-1986	TWGSAL	Extrapolated forwards using DWGSAL growth rates.
Detroit Edison Company	2005	DWGSAL	Averaged 2004 & 2006 values.
Duke Energy Kentucky, Inc.	1996	DWGSAL & TWGSAL	Averaged respective 1995 & 1997 values.
Illinois Power Company	2007-2009	OPREVI	Extrapolated forwards using MWHIND growth rates.
Illinois Power	1977	MWHCOM & MWHIND	Averaged respective 1976 & 1978 values.
Jersey Central Power & Light Company	2002	OPREVP	Averaged 2001 & 2003 values.
Jersey Central Power & Light Company	1999-2002	FTEMPLOY, PTEMPLOY, DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Kentucky Utilities Company	2005	RET	Averaged 2004 & 2006 values.
MDU Resources Group	1987	TWGSAL	Extrapolated forwards using DWGSAL growth rate.
Metropolitan Edison Company	1999-2002	FTEMPLOY, PTEMPLOY, DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Monongahela Power Company	1997-2001	FTEMPLOY & PTEMPLOY	Extrapolated forwards using TWGSAL growth rates.
Pennsylvania Electric Company	1999-2002	DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Public Service Company of New Hampshire	1991-1992	O&M	Averaged 1990 & 1993 values.
Virginia Electric and Power Company	2002	DWGSAL	Averaged 2001 & 2003 values.
Wisconsin Electric Power Company	1982	TWGSAL	Averaged 1981 & 1983 values.
Wisconsin Public Service Corp	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate.

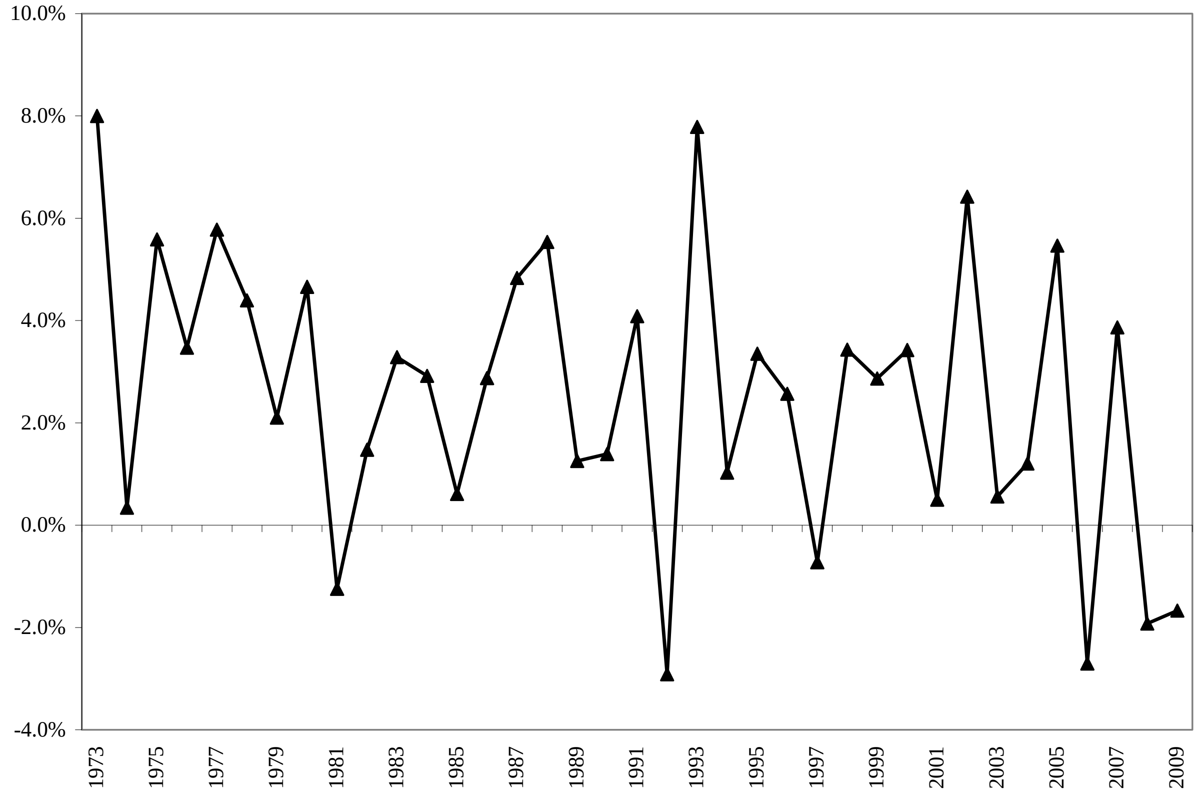
XI. APPENDIX III. Figures

Figure 1. Output shares, 1972-2009



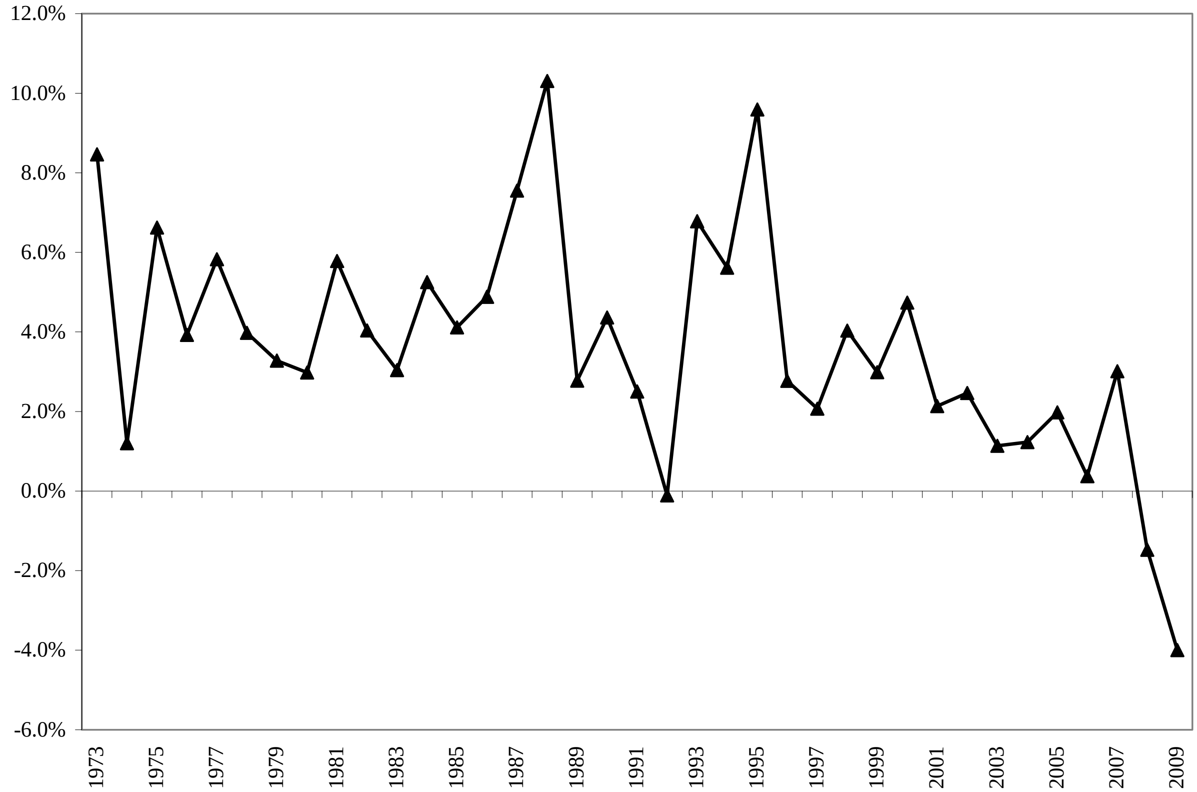
Source: NERA TFP Study

Figure 2. Residential output index growth, 1973-2009



Source: NERA TFP Study

Figure 3. Commercial output index growth, 1973-2009

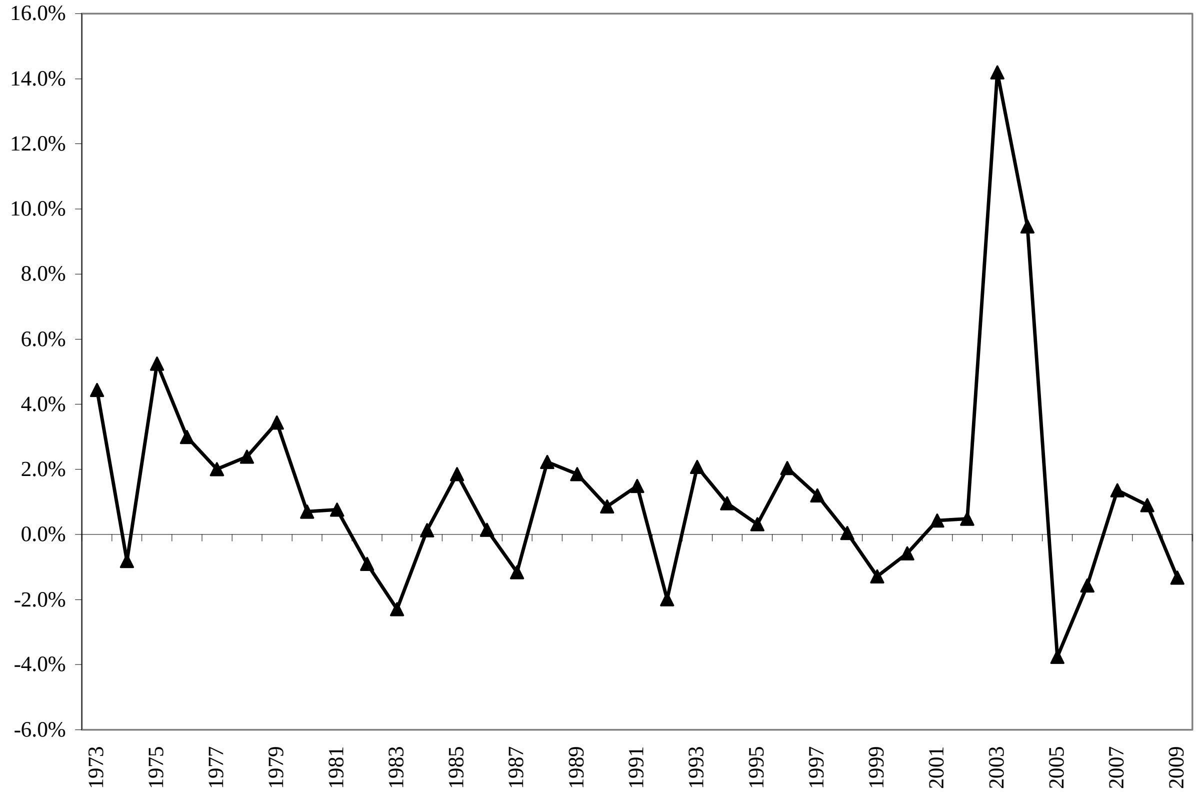


Source: NERA TFP Study

Figure 4. Industrial output index growth, 1973-2009

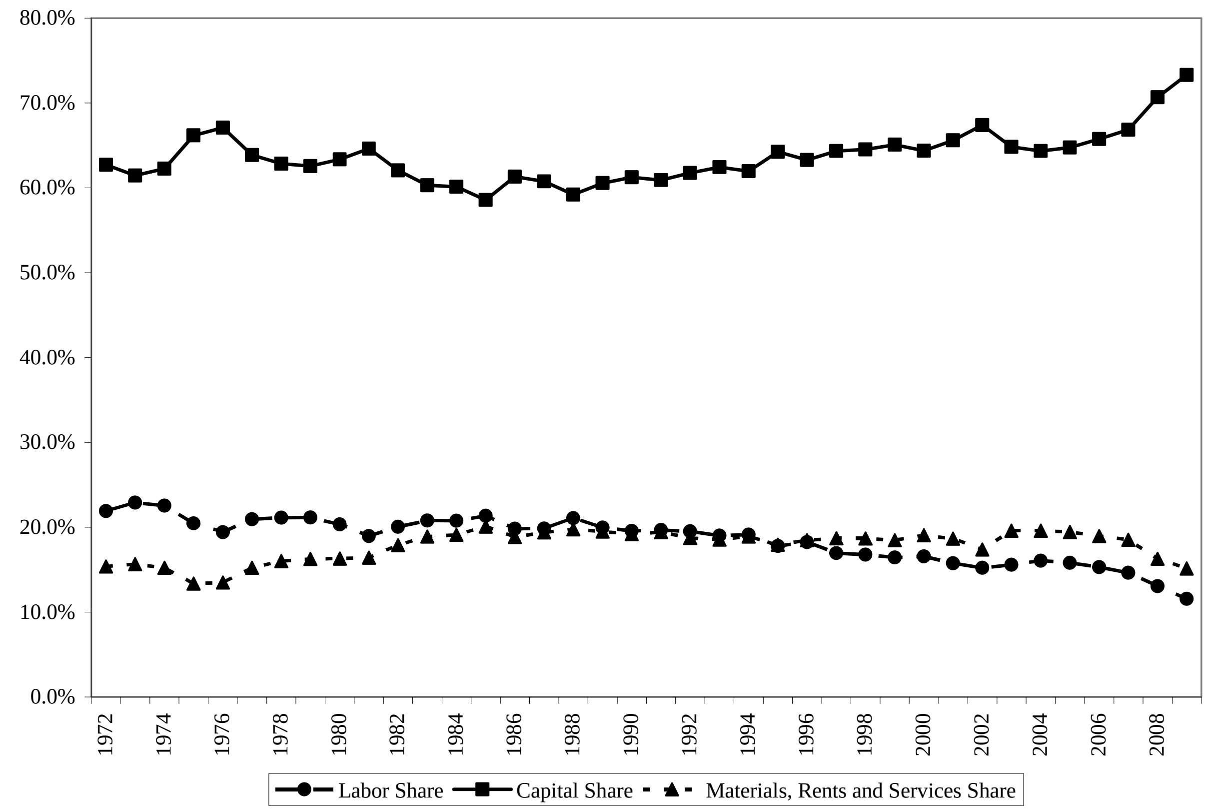
Source: NERA TFP Study

Figure 5. Public output index growth, 1973-2009



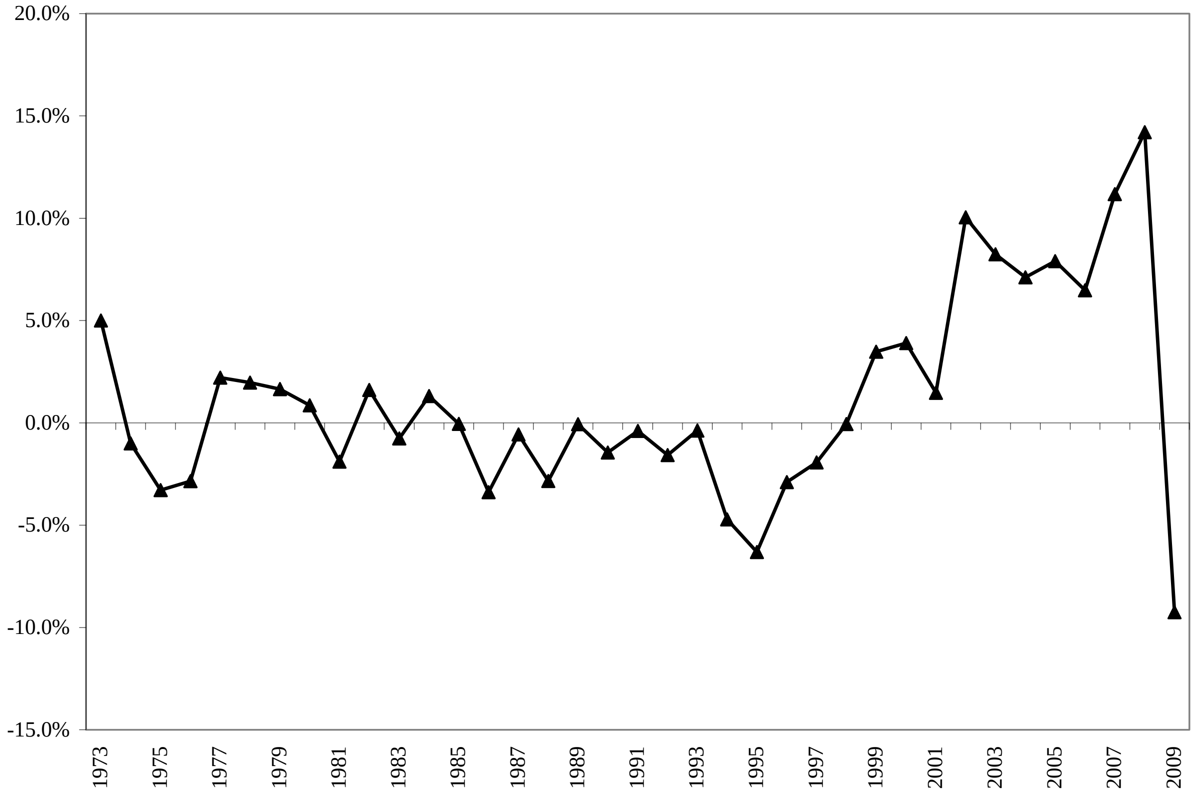
Source: NERA TFP Study

Figure 6. Input shares, 1972-2009



Source: NERA TFP Study

Figure 7. Labor input index growth, 1973-2009

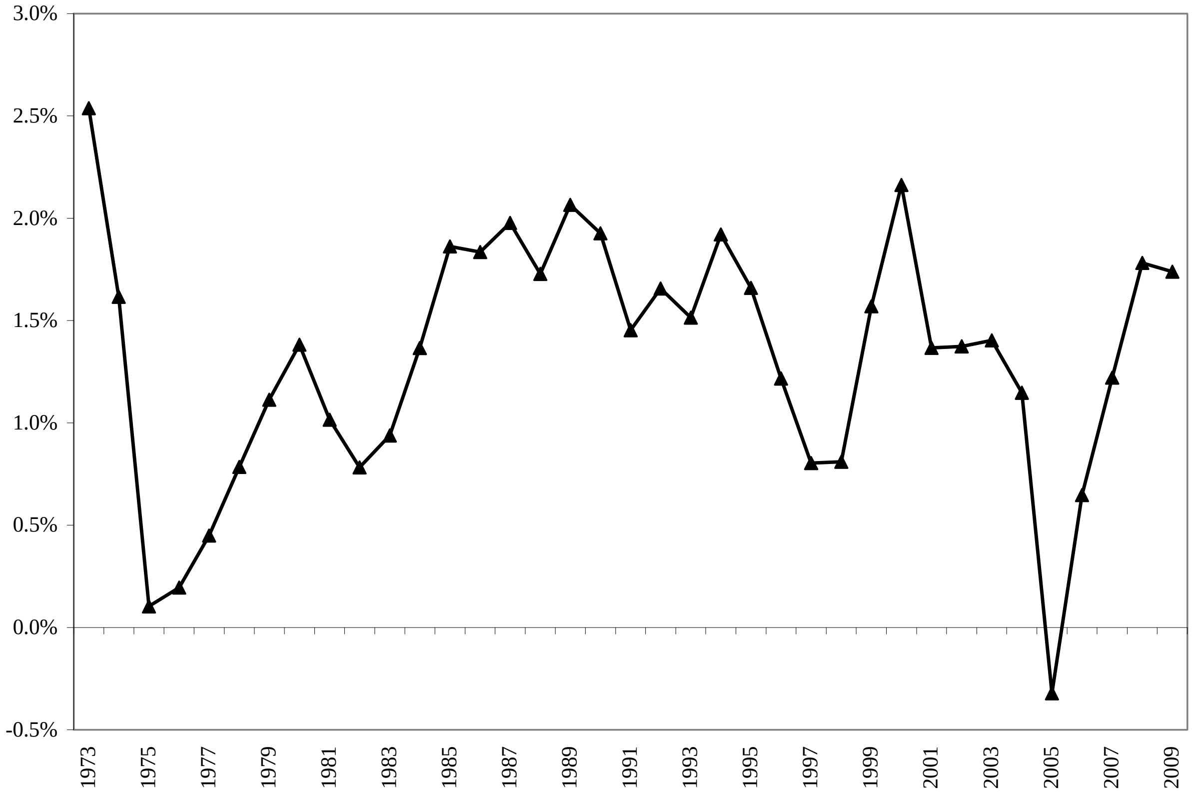


Source: NERA TFP Study

Figure 8. MRS input index growth, 1973-2009

Source: NERA TFP Study

Figure 9. Capital input index growth, 1973-2009

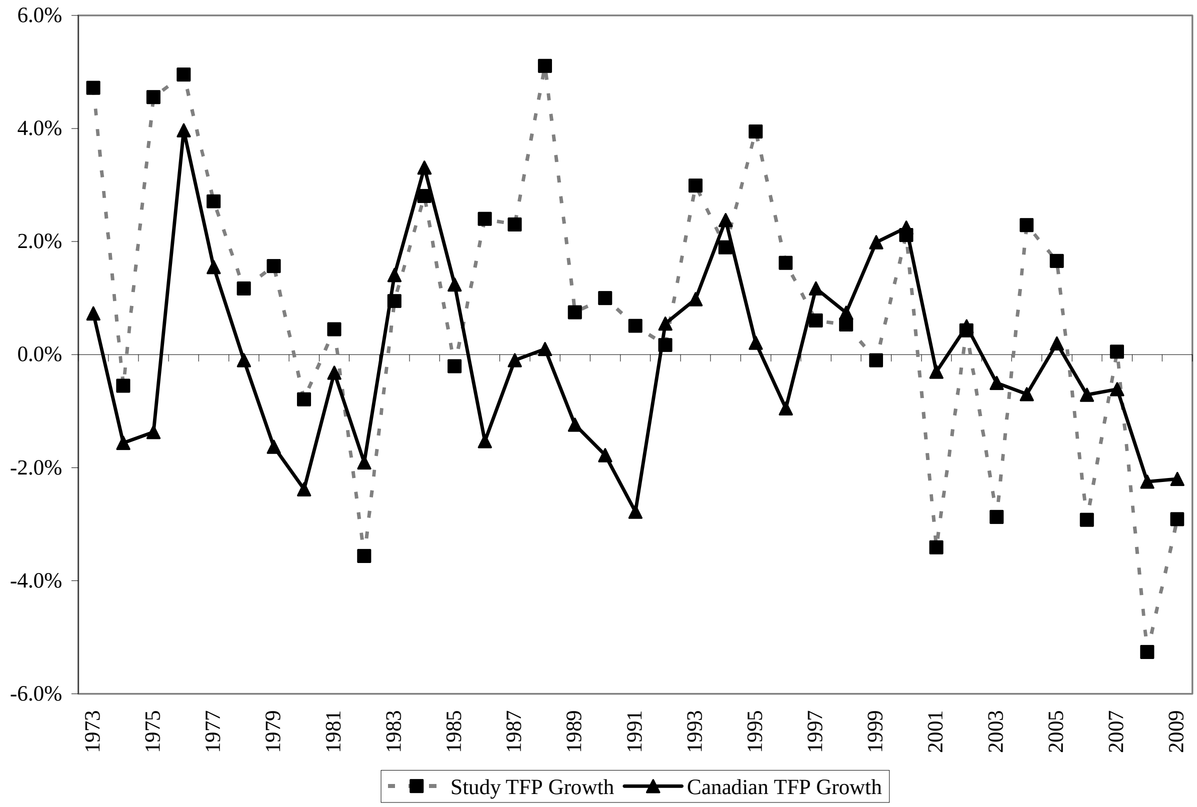


Source: NERA TFP Study

Figure 10. TFP growth, 1973-2009

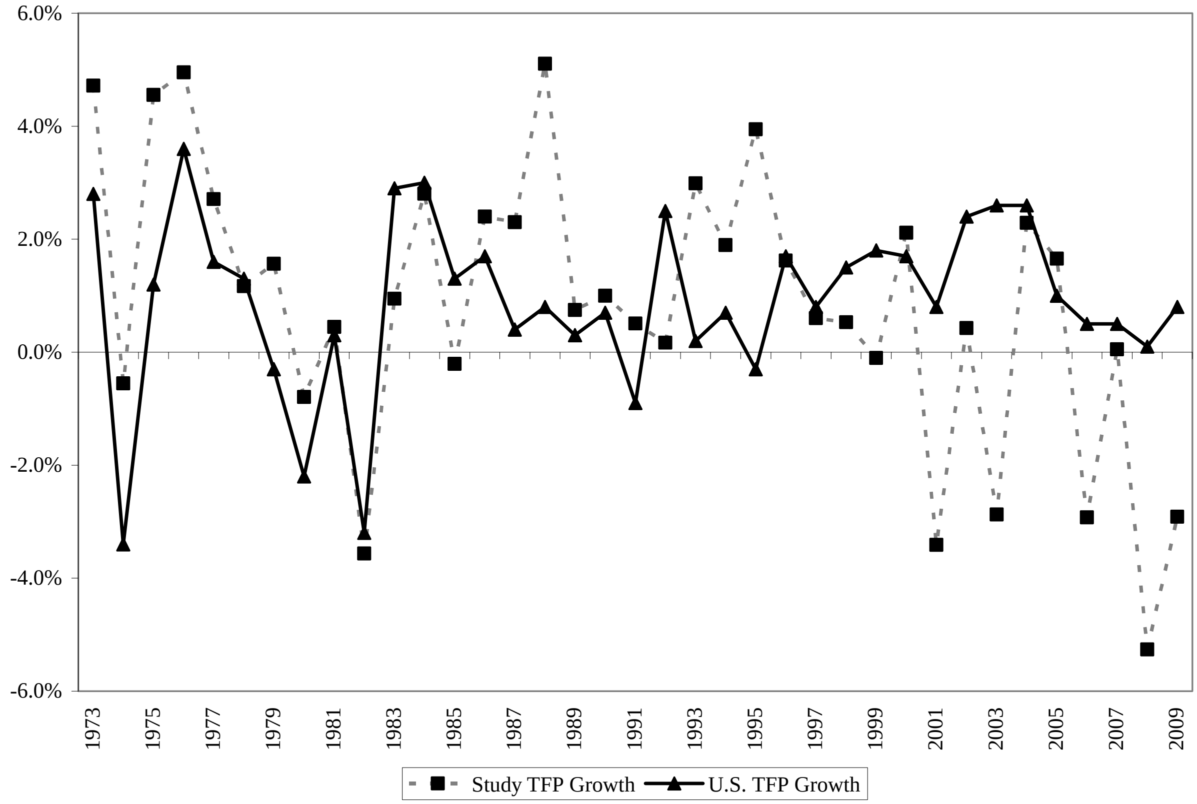
Source: NERA TFP Study

Figure 11. Study TFP growth and Canadian economy TFP growth, 1973-2009



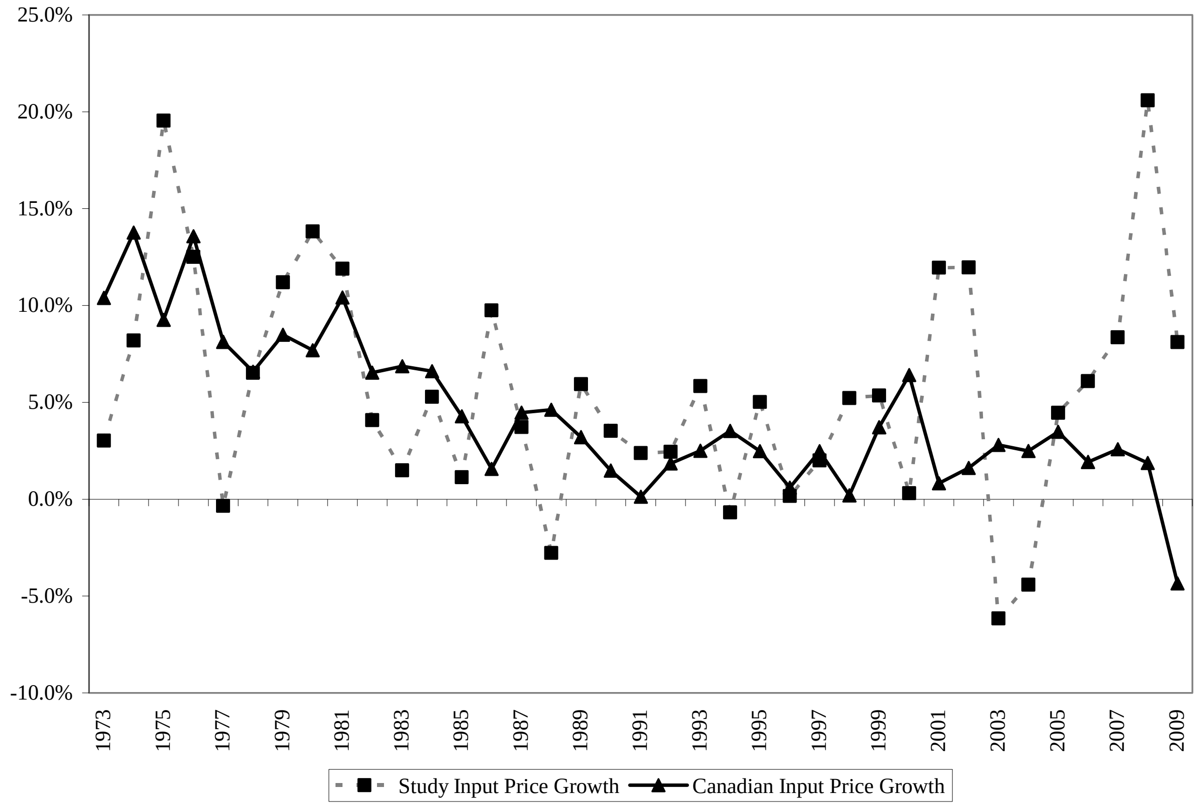
Source: NERA TFP Study and Statistics Canada

Figure 12. Study TFP growth and U.S. economy TFP growth, 1973-2009



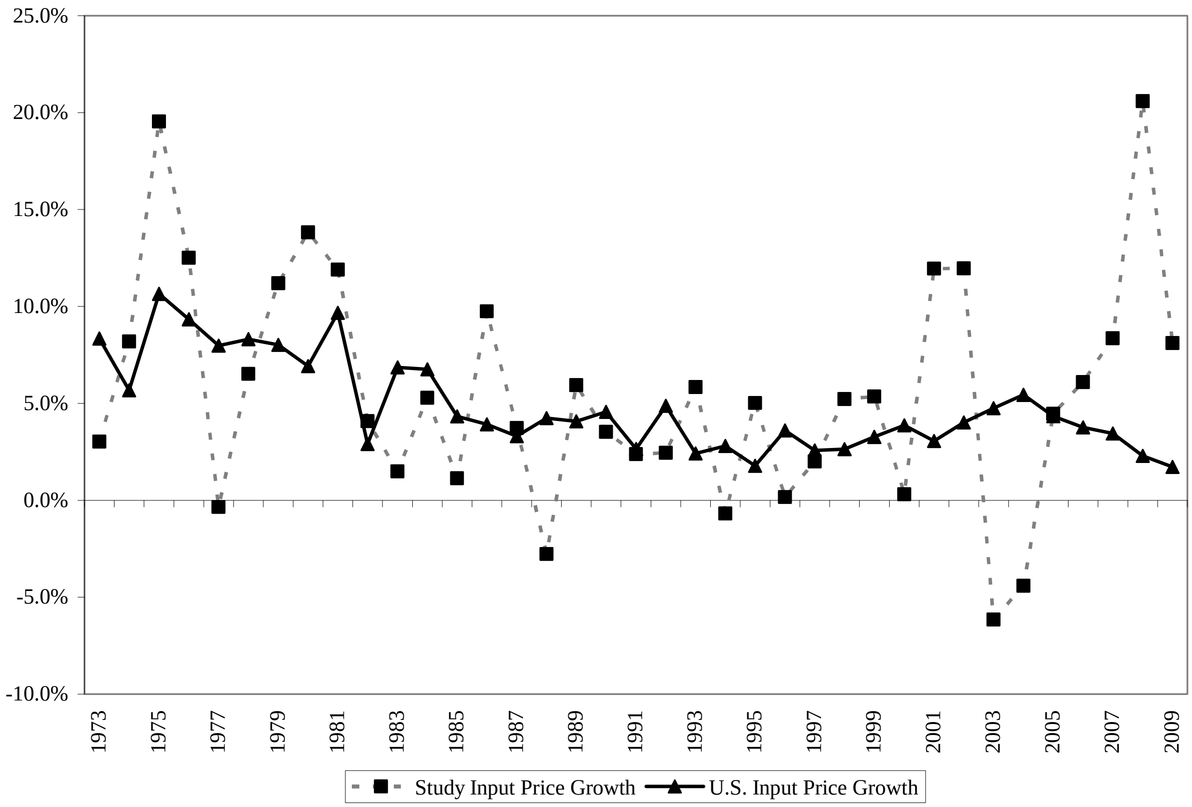
Source: NERA TFP Study and U.S. Bureau of Labor Statistics

Figure 13. Study input price growth and Canadian economy input price growth, 1973-2009



Source: NERA TFP Study and Statistics Canada

Figure 14. Study input price growth and U.S. economy input price growth, 1973-2009



Source: NERA TFP Study, U.S. Bureau of Labor Statistics and U.S. Bureau of Economic Analysis

NERA
Economic Consulting

200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
617+1 617 927 4500
617 +1 617 927 4501

Exhibit JDM-3, Tab 1: NERA Industry Study Summary Tables and Figures

I. List of companies used in the Industry Study

Alabama Power Company
Appalachian Power Company
Arizona Public Service Company
Baltimore Gas and Electric Company
Central Hudson Gas & Electric Corporation
Cleveland Electric Illuminating Company
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
DTE Electric Company
Duke Energy Indiana, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Green Mountain Power Corporation
Gulf Power Company
Idaho Power Co.
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Utilities Company
Madison Gas and Electric Company
Massachusetts Electric Company
MDU Resources Group, Inc.
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company
Narragansett Electric Company
Nevada Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Northern Indiana Public Service Company
NSTAR Electric Company
Ohio Edison Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.
Otter Tail Power Company
Pacific Gas and Electric Company
PECO Energy Company
Pennsylvania Electric Company
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Puget Sound Energy, Inc.
South Carolina Electric & Gas Co.
Southern California Edison Company
Southern Indiana Gas and Electric Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Tucson Electric Power Company
Virginia Electric and Power Company
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

II. List of changes made to original FERC data[1]

Company Name	Year (s)	Variable(s) Changed	Methodology
Appalachian Power Company	1972	TWGSAL	Extrapolated forward using DWGSAL growth rate
Cleveland Electric Illuminating Company	1975	TWGSAL	Averaged respective 1974 & 1975 values
Consolidated Edison Company of New York, Inc.	2002-2016	DWGSAL	Extrapolated forward using TWGSAL growth rate
Consolidated Edison Company of New York, Inc.	2008-2011	OPREVI, OPREVC, MWHCO, MWHIN	Extrapolated forward using OPREVR and MWHRES growth rates, repectively
Consolidated Edison Company of New York, Inc.	1983	DWGSAL	Averaged respective 1982 & 1984 values
Consumers Energy Company	1993	DWGSAL & TWGSAL	Averaged respective 1992 and 1994 values
Duke Energy Indiana, LLC	1995	DWGSAL & TWGSAL	Values from Alberta Study were taken as given
Duke Energy Kentucky, Inc.	1996	DWGSAL & TWGSAL	Averaged respective 1995 & 1997 values
Jersey Central Power & Light Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Jersey Central Power & Light Company	2002-2009	OPREVP	Values from Alberta Study were taken as given
Jersey Central Power & Light Company	2010-2016	OPREVP	Extrapolated forwards using OPREVR growth rate
Kentucky Utilities Company	2005	RET	Averaged respective 2004 and 2006 values
MDU Resources Group, Inc.	1987	TWGSAL	Extrapolated forwards using DWGSAL growth rate
Metropolitan Edison Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Monongahela Power Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Narrangsett Electric Company	1993	FTEMPLOY & PTEMPLOY	Values from Alberta Study were taken as given
PECO Energy Company	1993	FTEMPLOY & PTEMPLOY	Used value for Total Employees from SNL instead of deriving value from FTEMPLOY & PTEMPLOY
PECO Energy Company	1988	FTEMPLOY & PTEMPLOY	Used PTEMPLOY value reported by SNL for FTEMPLOY
Pennsylvania Electric Company	1999-2002	DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values
Public Service Company of Colorado	1993	FTEMPLOY & PTEMPLOY	Values from Alberta Study were taken as given
Virginia Electric and Power Company	2002	DWGSAL	Averaged respective 2001 and 2003 values
Wisconsin Public Service Corporation	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate
Wisonsin Electric Power Company	1982	TWGSAL	Averaged respective 1981 & 1983 values

[1] For these FERC Form 1 data points, it was necessary to estimate values because I determined that the values were too extreme to be correct or they were missing altogether. In some cases, I took the values used in my previous report in Alberta Proceeding 566 as given (this report is denoted as "the Alberta Study" in the table above).

III. Industry Study Tables

Table 1. Industry TFP Study, output shares and output index growth, 1972-2016[2]

Service	Share of Output	Output Index Growth Rate
	(percent)	
Residential	42.04%	2.19%
Commercial	32.30%	2.96%
Industrial	22.44%	1.24%
Public	3.22%	0.95%

Table 2. Industry TFP Study, input shares and input index growth, 1972-2016[3]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	17.86%	0.71%
MRS	17.54%	4.49%
Capital	64.60%	1.44%

[2] Source: NERA Industry TFP Study, share of output and growth rates are unweighted.

[3] Source: NERA Industry TFP Study, share of input and growth rates are unweighted.

Table 3. Industry TFP Study, output, input and TFP growth, 1973-2016[4]

Year	Output growth	Input growth	TFP growth
	(percent)		
1973	7.38	2.66	4.71
1974	-0.59	0.21	-0.80
1975	2.24	-2.31	4.55
1976	4.99	0.25	4.74
1977	4.00	1.60	2.40
1978	3.34	2.27	1.07
1979	2.91	1.06	1.85
1980	1.11	1.97	-0.86
1981	1.03	0.12	0.91
1982	-0.93	2.69	-3.62
1983	2.86	2.06	0.80
1984	4.46	1.67	2.79
1985	1.97	2.17	-0.20
1986	2.73	0.40	2.33
1987	4.16	1.77	2.39
1988	4.80	-0.35	5.15
1989	2.02	1.57	0.45
1990	1.59	0.92	0.67
1991	2.40	2.08	0.33
1992	-0.54	-0.67	0.13
1993	3.79	2.04	1.75
1994	2.20	0.39	1.81
1995	2.77	-1.32	4.09
1996	1.89	0.36	1.53
1997	1.03	0.75	0.28
1998	3.01	2.77	0.24
1999	1.76	0.17	1.58
2000	3.06	1.14	1.92
2001	-0.94	1.91	-2.85
2002	3.09	0.93	2.16
2003	0.49	3.29	-2.80
2004	2.15	-1.10	3.25
2005	3.12	0.74	2.38
2006	-0.34	2.63	-2.97
2007	2.80	1.95	0.84
2008	-1.26	3.65	-4.92
2009	-4.37	-1.51	-2.86
2010	3.45	1.40	2.05
2011	-1.43	2.95	-4.38
2012	-1.20	0.94	-2.13
2013	0.01	0.37	-0.36
2014	0.16	2.03	-1.88
2015	-0.23	1.13	-1.36
2016	-0.20	3.32	-3.52
Average	1.74	1.21	0.54

[4] Note: Output, input and TFP growth in each year are weighted by total mWh. Source: NERA Industry TFP Study.

Table 4. Industry Study TFP growth, Canadian economy TFP growth and X-factor calculation, 1973-2016[5]

Year	Study TFP Growth	Canadian TFP Growth
	(percent)	
1973	4.71	1.04
1974	-0.80	-1.30
1975	4.55	-0.34
1976	4.74	3.93
1977	2.40	1.92
1978	1.07	0.26
1979	1.85	-1.45
1980	-0.86	-2.11
1981	0.91	0.34
1982	-3.62	-1.15
1983	0.80	1.65
1984	2.79	3.43
1985	-0.20	1.10
1986	2.33	-1.50
1987	2.39	0.31
1988	5.15	0.21
1989	0.45	-0.95
1990	0.67	-1.81
1991	0.33	-2.64
1992	0.13	0.70
1993	1.75	1.11
1994	1.81	2.43
1995	4.09	0.37
1996	1.53	-0.92
1997	0.28	1.06
1998	0.24	0.63
1999	1.58	2.38
2000	1.92	2.12
2001	-2.85	0.06
2002	2.16	1.29
2003	-2.80	-0.73
2004	3.25	-0.32
2005	2.38	0.04
2006	-2.97	-0.82
2007	0.84	-1.14
2008	-4.92	-2.30
2009	-2.86	-2.57
2010	2.05	1.78
2011	-4.38	1.49
2012	-2.13	-0.61
2013	-0.36	0.91
2014	-1.88	1.33
2015	-1.36	-1.00
2016	-3.52	*0.19*
Average	0.54	0.19
X-Factor	0.35	

[5] Source: Industry TFP growth: NERA Industry TFP Study, Industry TFP growth is weighted by total mWh; Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. For 2016, I assume that Canadian TFP is equal to the average TFP over the time period 1973-2015, since Statistics Canada has not yet published a TFP figure for this year.

Table 5. Industry Study input price growth and US economy input price growth, 1973-2016[6]

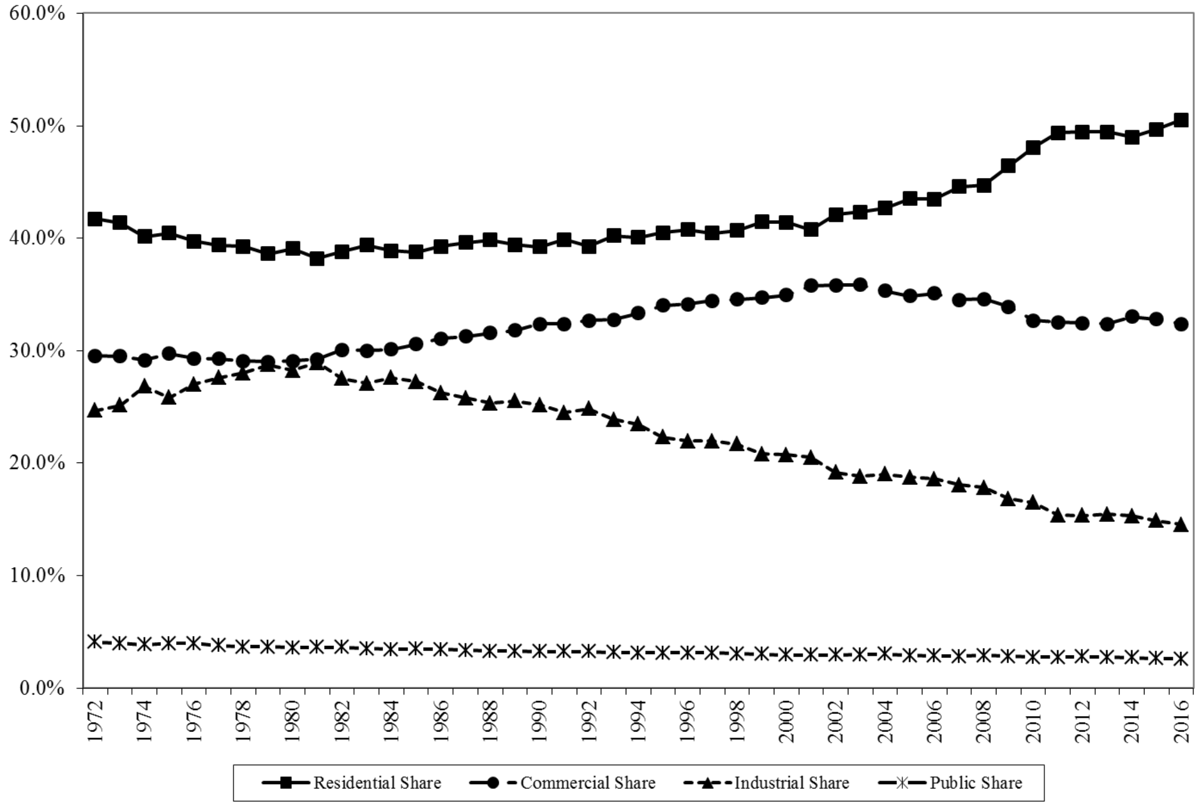
Year	Input price growth	US Input Price Growth
	---(percent)---	
1973	3.22	8.50
1974	8.14	5.40
1975	19.12	10.40
1976	11.96	9.20
1977	0.03	8.10
1978	6.62	8.60
1979	11.00	7.50
1980	13.80	6.60
1981	12.01	9.40
1982	3.78	4.10
1983	1.91	4.20
1984	5.25	7.30
1985	1.30	3.40
1986	9.41	2.10
1987	3.63	4.20
1988	-2.71	4.10
1989	6.01	4.20
1990	3.37	3.90
1991	2.41	1.40
1992	2.54	4.90
1993	5.87	2.10
1994	-0.47	2.00
1995	4.97	1.40
1996	0.41	3.40
1997	1.91	2.60
1998	5.42	1.90
1999	5.35	2.90
2000	5.57	3.60
2001	35.65	2.30
2002	-2.40	2.50
2003	-5.92	4.20
2004	-3.54	5.50
2005	5.11	4.70
2006	6.29	3.30
2007	8.56	3.50
2008	19.60	1.60
2009	8.21	-1.60
2010	-8.03	4.00
2011	1.59	2.30
2012	5.65	1.80
2013	0.28	2.30
2014	1.87	1.80
2015	8.67	1.20
2016	1.31	*4.11*
Average	5.34	4.11

t-statistic	Critical value (two-tail)	Degrees of freedom
1.1504	2.021	42

[6] Source: Industry Input Price Growth: NERA Industry TFP Study, Industry input price growth is weighted by total mWh; US Input Price Growth: U.S. Bureau of Labor Statistics (BLS), Net Multifactor Productivity and Cost (Private Business Sector), Table PG 4.3 available at: https://www.bls.gov/mfp/mprdload.htm. I estimate input price growth for the US economy in 2016, using the average input price growth for 1973-2015, since I did not have data for 2016 at the time of my analysis. The difference in means test encompasses the years 1973-2015.

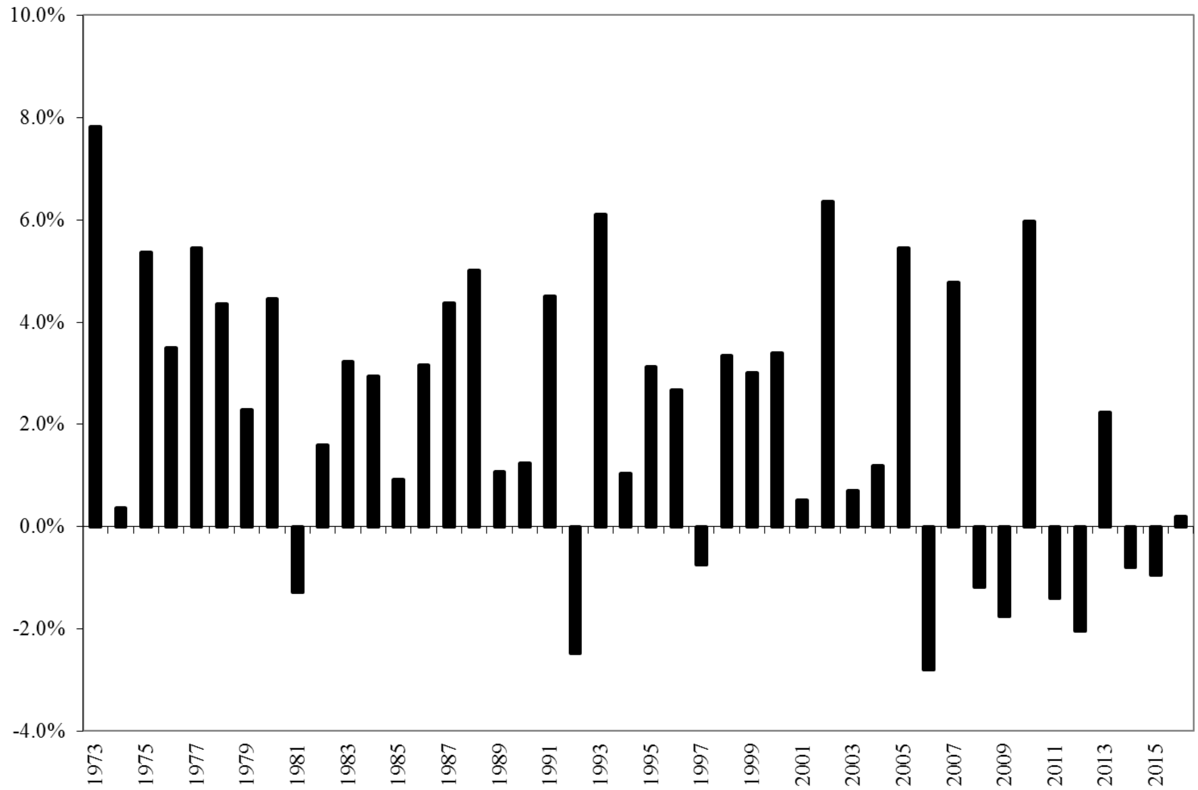
IV. Industry Study Figures

Figure 1. Output shares, 1972-2016



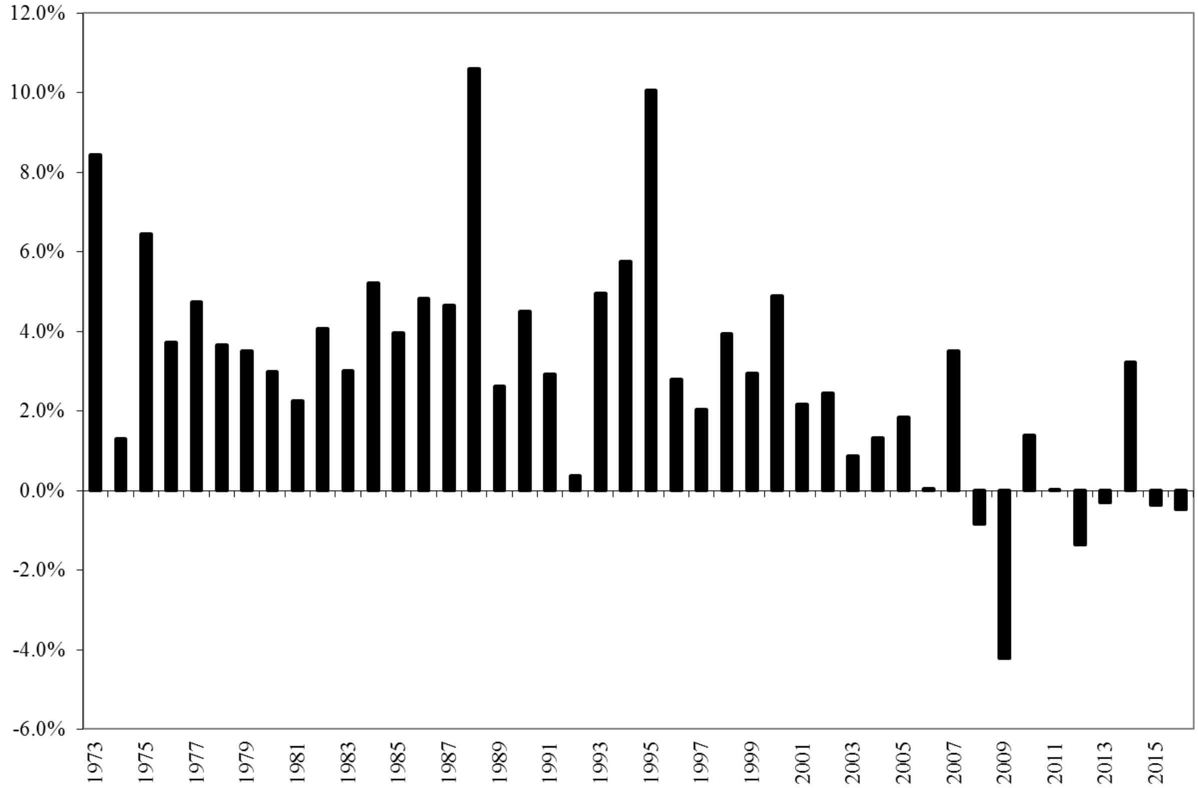
Source: NERA Industry TFP Study

Figure 2. Residential output index growth, 1973-2016



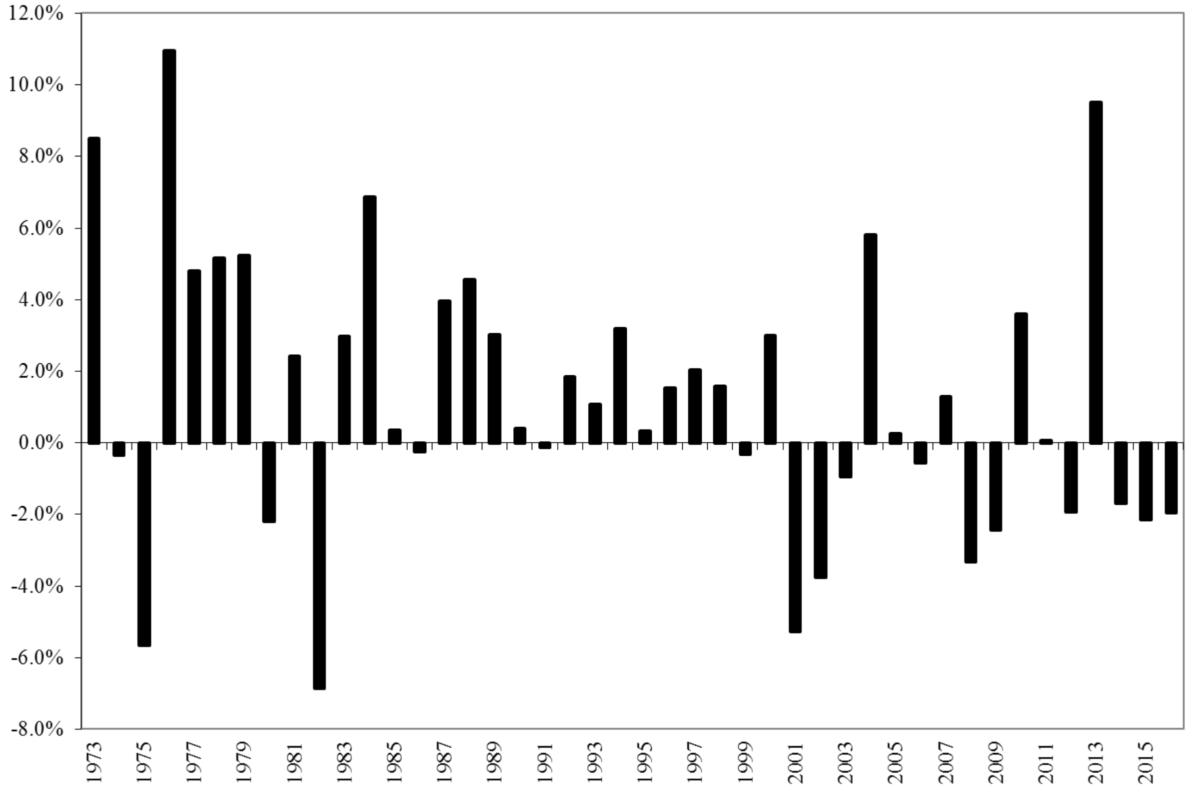
Source: NERA Industry TFP Study

Figure 3. Commercial output index growth, 1973-2016



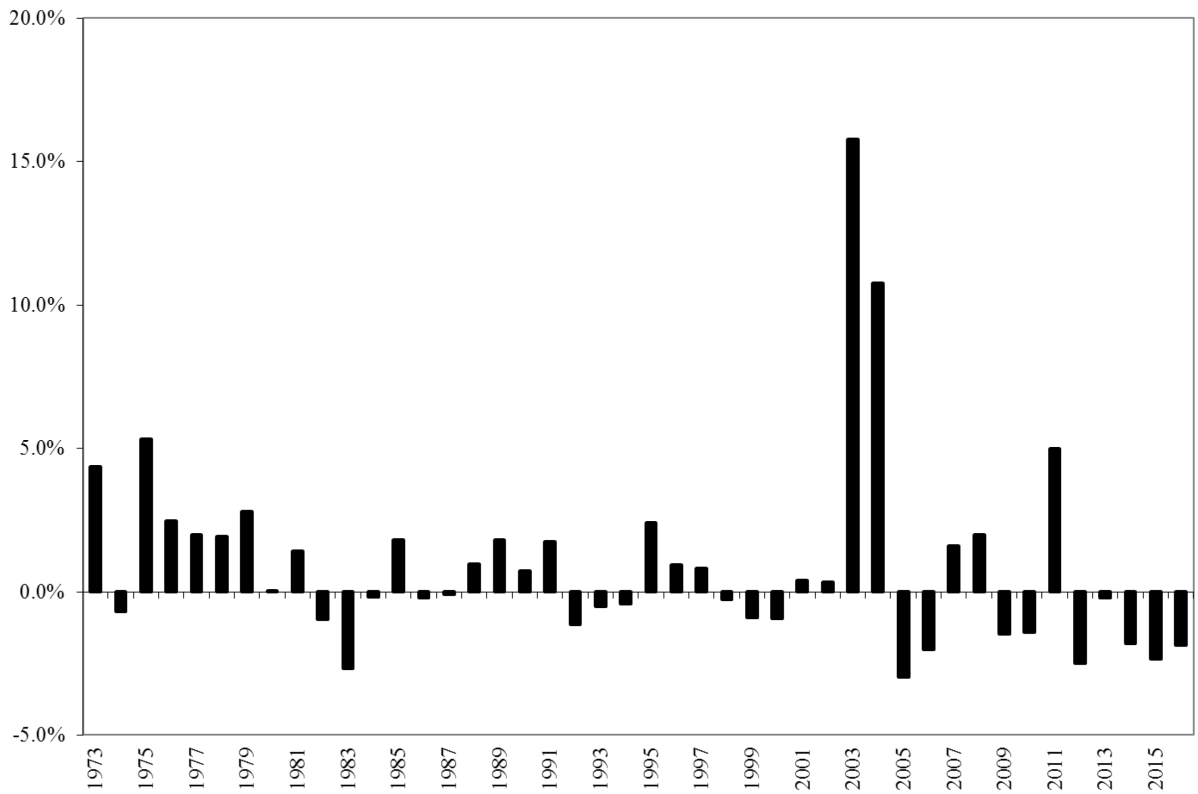
Source: NERA Industry TFP Study

Figure 4. Industrial output index growth, 1973-2016



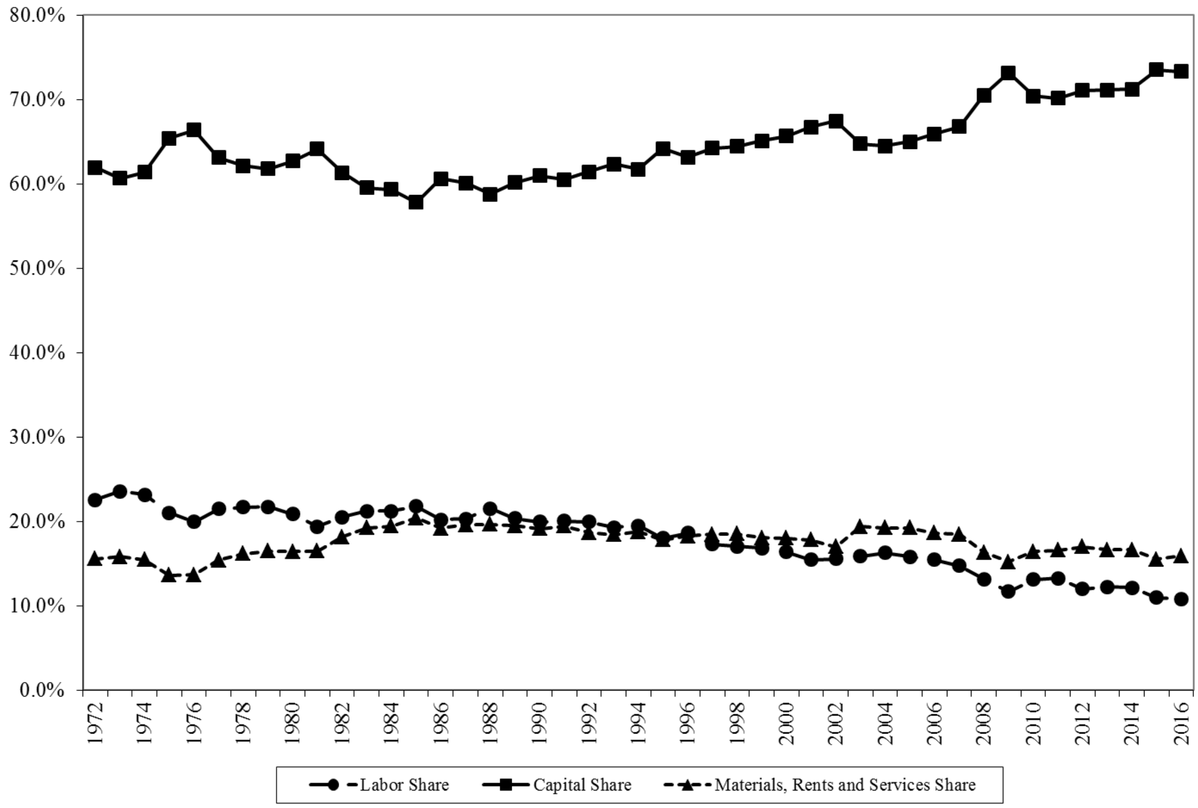
Source: NERA Industry TFP Study

Figure 5. Public output index growth, 1973-2016



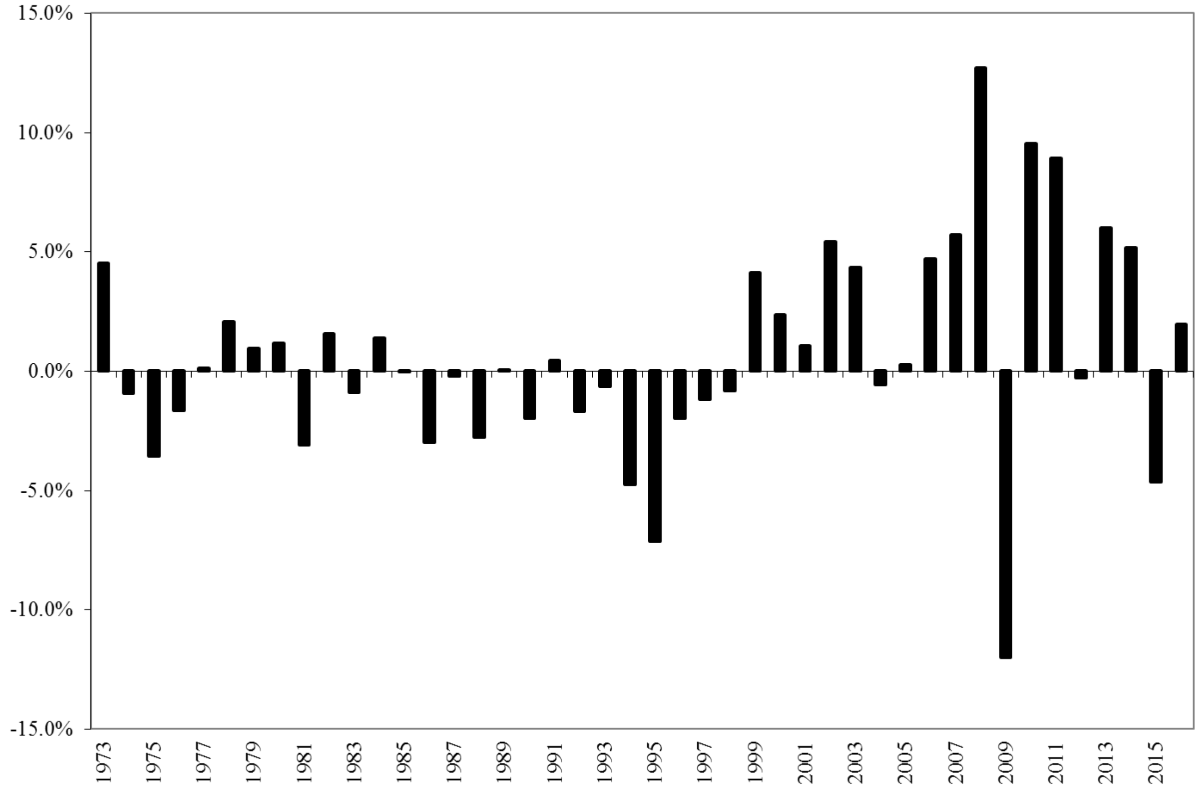
Source: NERA Industry TFP Study

Figure 6. Input shares, 1972-2016



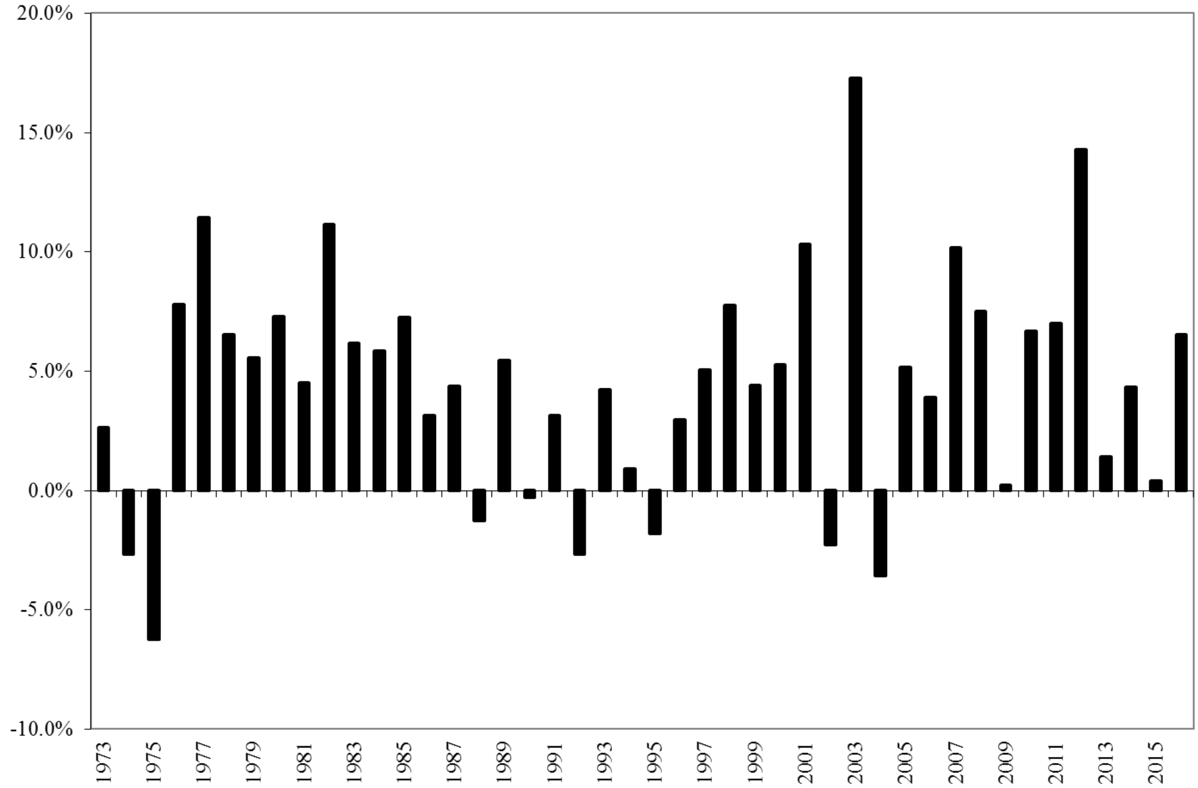
Source: NERA Industry TFP Study

Figure 7. Labor input index growth, 1973-2016



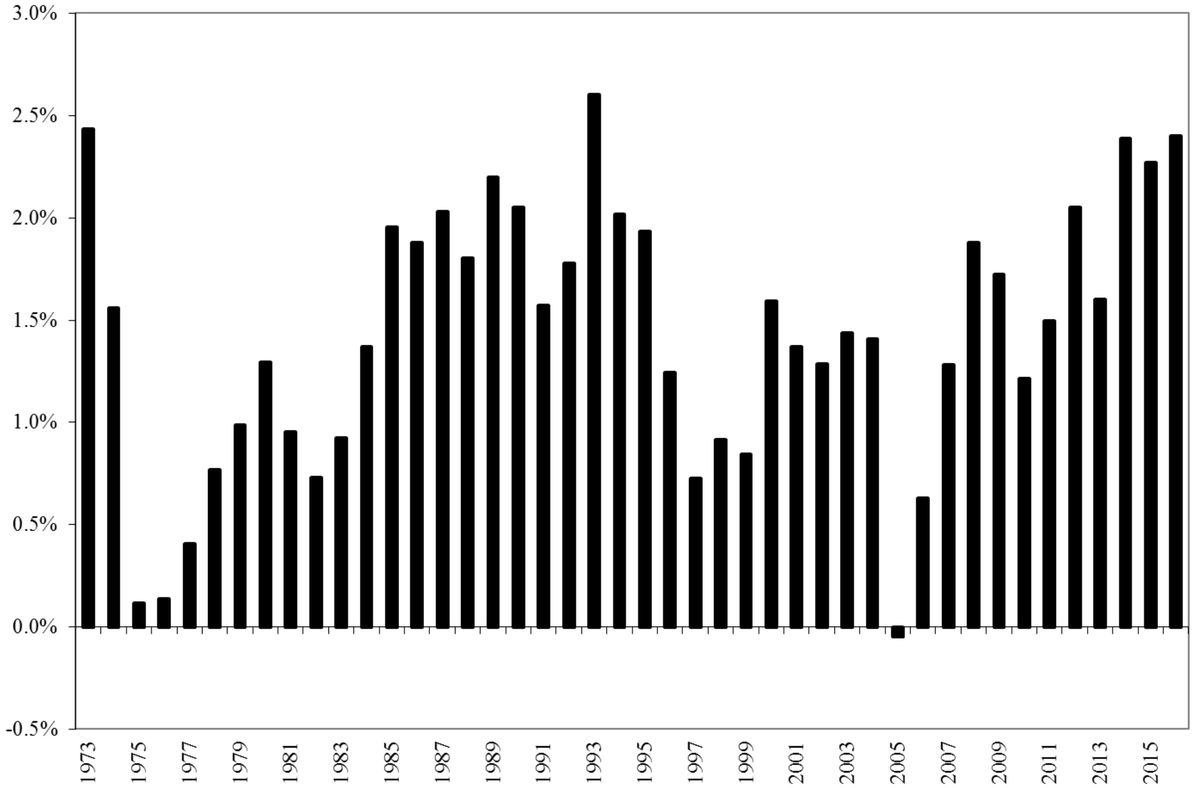
Source: NERA Industry TFP Study

Figure 8. MRS input index growth, 1973-2016



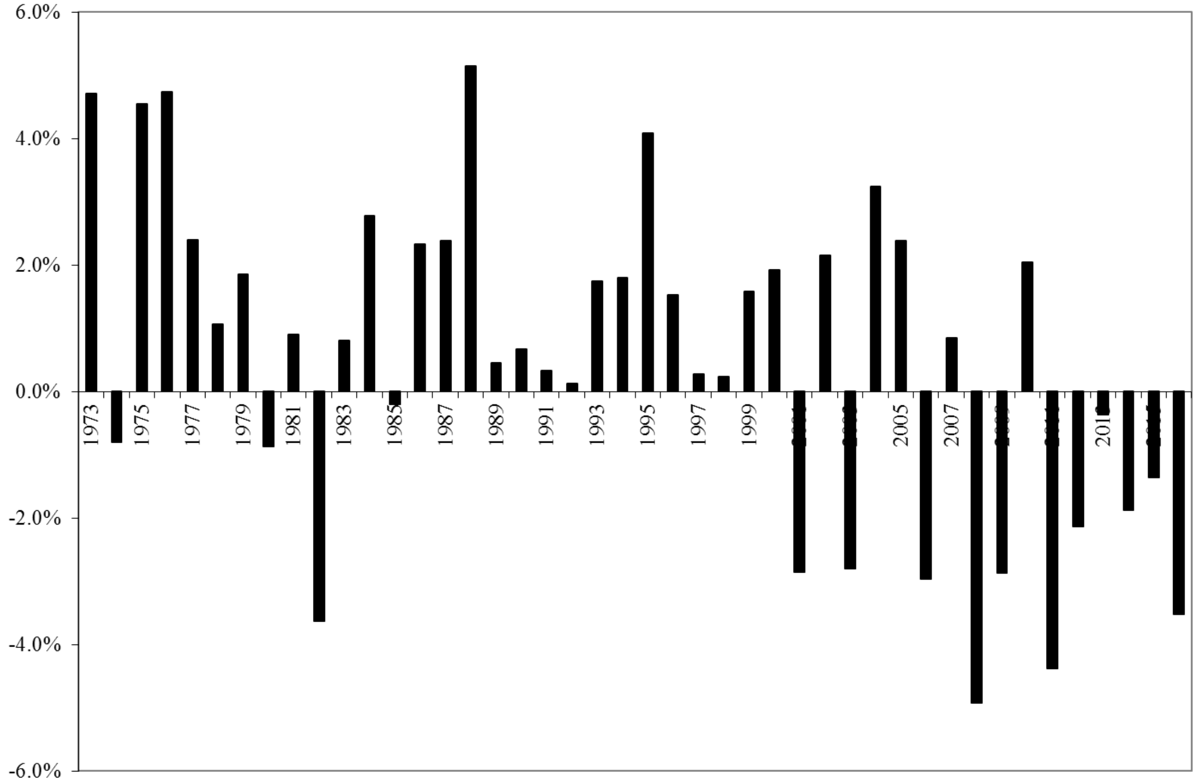
Source: NERA Industry TFP Study

Figure 9. Capital input index growth, 1973-2016



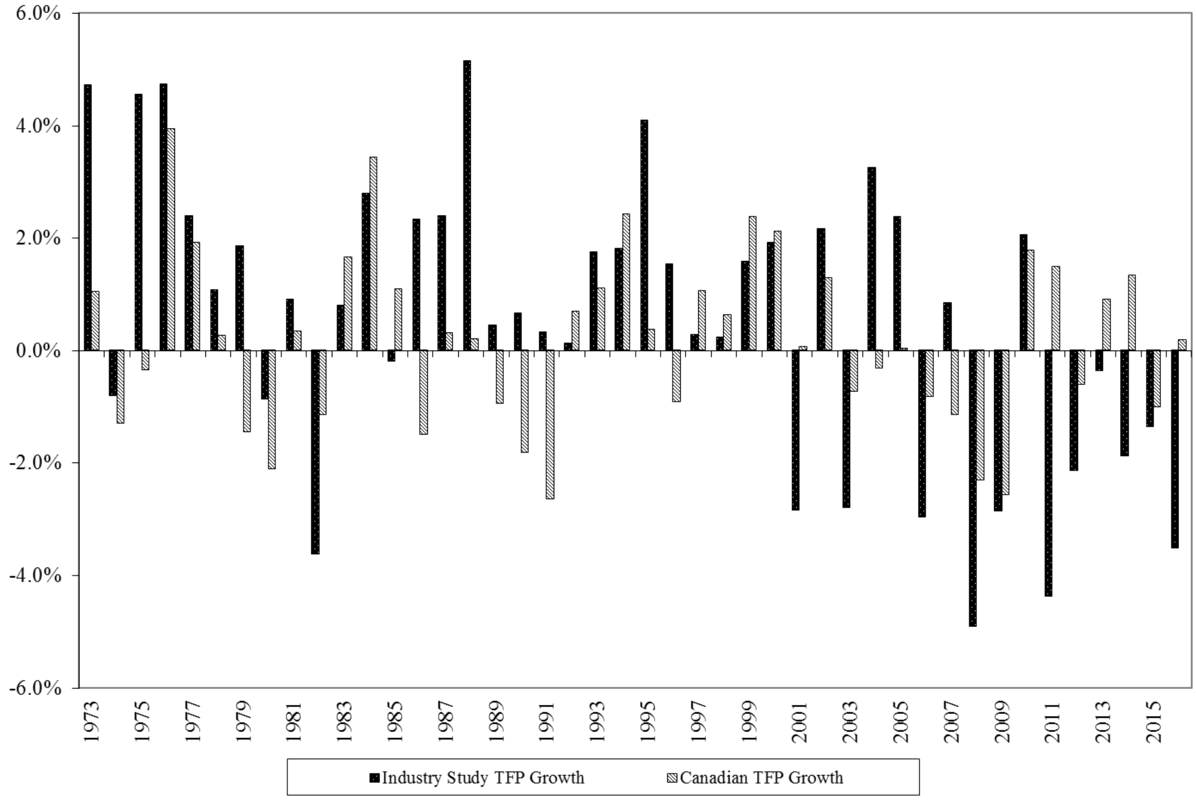
Source: NERA Industry TFP Study

Figure 10. Industry TFP growth, 1973-2016



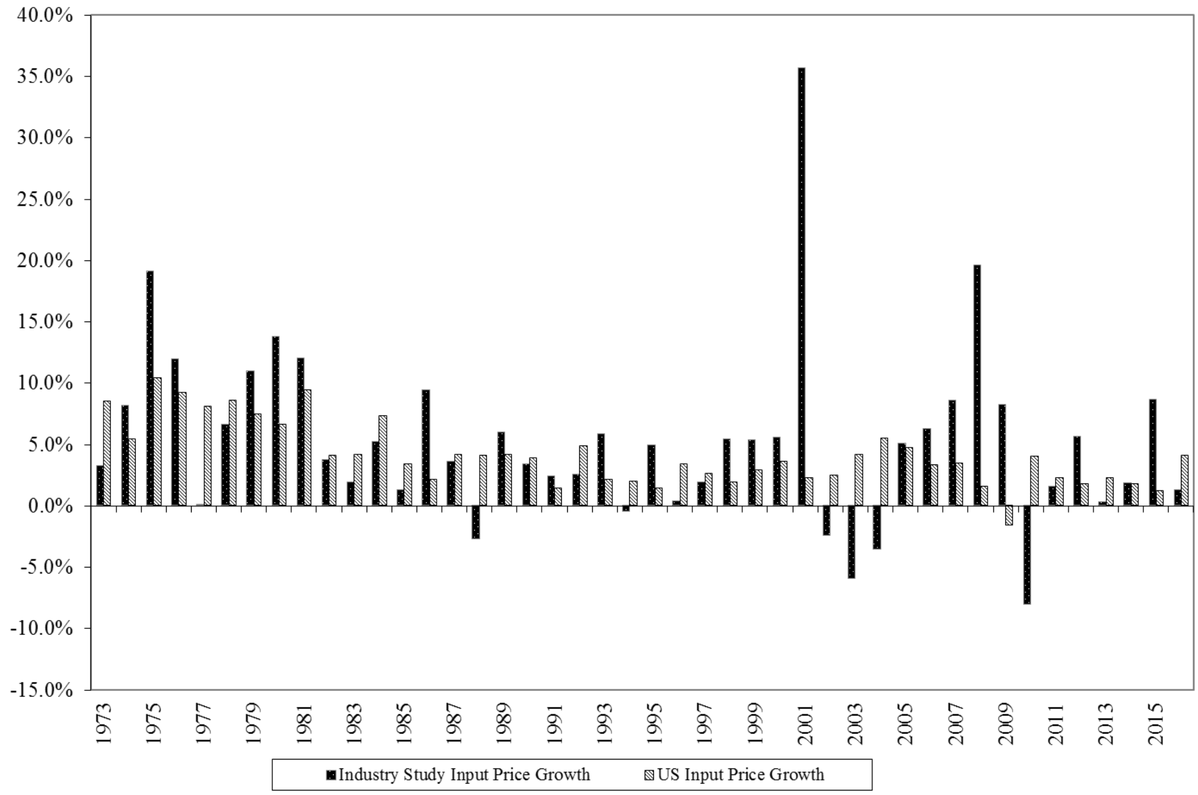
Source: NERA Industry TFP Study

Figure 11. Industry TFP growth and Canadian economy TFP growth, 1973-2016



Source: NERA Industry TFP Study and Statistics Canada

Figure 12. Industry input price growth and US economy input price growth, 1973-2016



Source: NERA Industry TFP Study and US Bureau of Labor Statistics

Exhibit JDM-3, Tab 2: NERA EGD Study Summary Tables and Figures

I. Sources for EGD Data Set

	Output Quantity: Sales Volume				Output Shares: Operating Revenues			
Year	**Residential**	**Commercial**	**Industrial**	**Other (Wholesale)**	**Residential**	**Commerical**	**Industrial**	**Other (Wholesale)**
1992	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4
1993	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4
1994	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4
1995	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4
1996	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4
1997	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3
1998	Company provided data	Company provided data	Company provided data	Company provided data	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3
1999	Company provided data	Company provided data	Company provided data	Company provided data	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3
2000	Company provided data	Company provided data	Company provided data	Company provided data	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3
2001	Company provided data	Company provided data	Company provided data	Company provided data	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3
2002	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2001 and 2003 values	Average of 2001 and 2003 values	Average of 2001 and 2003 values	Average of 2001 and 2003 values
2003	Company provided data	Company provided data	Company provided data	Company provided data	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3
2004	Company provided data	Company provided data	Company provided data	Company provided data	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3
2005	Company provided data	Company provided data	Company provided data	Company provided data	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3
2006	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2005 and 2007 values	Average of 2005 and 2007 values	Average of 2005 and 2007 values	Average of 2005 and 2007 values
2007	Company provided data	Company provided data	Company provided data	Company provided data	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3
2008	Company provided data	Company provided data	Company provided data	Company provided data	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3
2009	Company provided data	Company provided data	Company provided data	Company provided data	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3
2010	Company provided data	Company provided data	Company provided data	Company provided data	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3
2011	Company provided data	Company provided data	Company provided data	Company provided data	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3
2012	Company provided data	Company provided data	Company provided data	Company provided data	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3
2013	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2012 and 2014 values	Average of 2012 and 2014 values	Average of 2012 and 2014 values	Average of 2012 and 2014 values
2014	Company provided data	Company provided data	Company provided data	Company provided data	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3
2015	Company provided data	Company provided data	Company provided data	Company provided data	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3
2016	Company provided data	Company provided data	Company provided data	Company provided data	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3

	Labor		Materials	Capital					
Year	FTEs	Wages & Salaries	Operations & Mainenance Expense	Additions to Distribution Plant	Retirements to Distribution Plant	Distribution Plant in Service	Storage Plant in Service	General Plant in Service	Total Net Plant in Service
1992	EBRO 485, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 485, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 485, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1993	EBRO 487, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 487, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 487, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1994	EBRO 490, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 490, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 490, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1995	EBRO 492, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 492, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 492, Exhibit D5, Tab 3, Schedule 2, p. 3	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1996	EBRO 495, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 495, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 495, Exhibit D5, Tab 3, Schedule 2, p. 3	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1997	EBRO 497, EBO 170-14, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 497, EBO 170-14, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 497, EBO 179-14, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1998	Average of 1997 and 2000 values	Average of 1997 and 2000 values	RP-1999-0001, Exhibit D5, Tab 1, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1999	Average of 1997 and 2000 values	Average of 1997 and 2000 values	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2000	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2001	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2002	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2003	Company provided data	Company provided data	RP-2003-0203, Exhibit D3, Tab 4, Schedule 1, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2004	Company provided data	Company provided data	EB-2005-0001, Exhibit A6, Tab 1, Schedule 1, p. 12	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2005	Company provided data	Company provided data	EB-2006-0034, Exhibit D1, Tab 1, Schedule 1, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2006	Company provided data	Company provided data	Average of 2005 and 2007 values	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2007	Company provided data	Company provided data	EB-2008-0219, Exhibit D, Tab 3, Schedule 1, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2008	Company provided data	Company provided data	EB-2009-0055, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2009	Company provided data	Company provided data	EB-2010-0042, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2010	Company provided data	Company provided data	EB-2011-0008, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2011	Company provided data	Company provided data	EB-2011-0354, Exhibit D1, Tab 3, Schedule 1, p. 11	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2012	Company provided data	Company provided data	EB-2013-0046, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2013	Company provided data	Company provided data	EB-2012-0459, Exhibit D1, Tab 3, Schedule 1, p. 27	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2014	Company provided data	Company provided data	EB-2015-05-0122, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2015	Company provided data	Company provided data	EB-2016-0142, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2016	Company provided data	Company provided data	EB-2017-0102, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data

II. EGD Study Tables

Table 1. EGD TFP Study, output shares and output index growth, 1992-2016[7]

Service	Share of Output	Output Index Growth Rate
	(percent)	
Residential	59.28%	1.45%
Commercial	32.33%	0.49%
Industrial	6.84%	0.18%
Other	1.55%	-0.05%

Table 2. EGD TFP Study, input shares and input index growth, 1992-2016[8]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	6.80%	1.69%
MRS	16.60%	0.62%
Capital	76.59%	1.11%

[7] Source: NERA EGD TFP Study, share of output and growth rates are unweighted.

[8] Source: NERA EGD TFP Study, share of input and growth rates are unweighted.

Table 3. EGD TFP Study, output, input and TFP growth, 1993-2016[9]

Year	Output growth	Input growth	TFP growth
	(percent)		
1993	4.33	3.10	1.22
1994	3.19	1.32	1.87
1995	-3.00	1.21	-4.21
1996	8.98	1.94	7.04
1997	-2.76	0.90	-3.65
1998	-6.04	-1.36	-4.68
1999	3.76	0.40	3.35
2000	5.37	-2.72	8.10
2001	1.43	1.62	-0.18
2002	0.01	0.94	-0.93
2003	9.57	2.79	6.78
2004	-2.60	0.25	-2.85
2005	0.79	0.71	0.08
2006	-8.34	0.96	-9.30
2007	9.22	0.84	8.39
2008	0.08	0.06	0.03
2009	-2.97	-0.19	-2.78
2010	-2.88	0.20	-3.08
2011	4.18	0.63	3.56
2012	-8.50	1.83	-10.33
2013	11.26	1.93	9.33
2014	6.58	0.43	6.16
2015	-6.32	1.61	-7.94
2016	-6.49	4.58	-11.07
Average	0.79	1.00	-0.21

[9] Source: NERA EGD TFP Study.

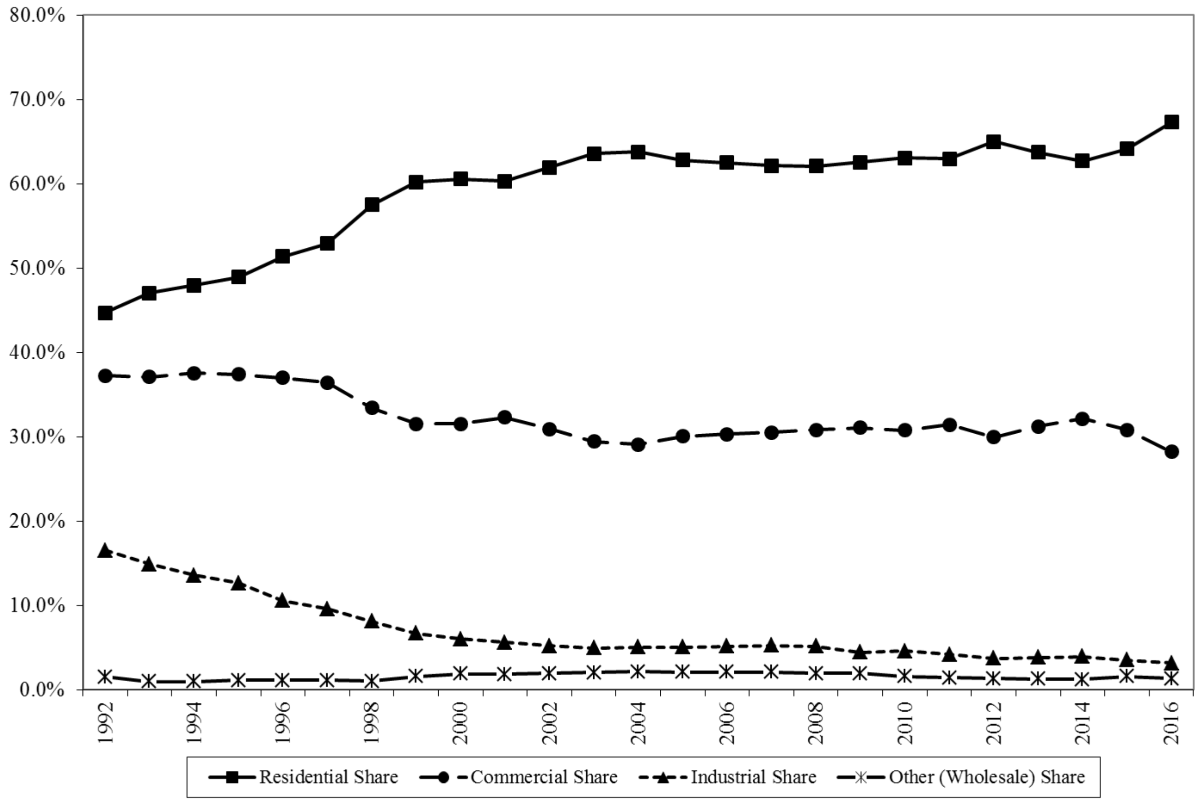
Table 4. EGD Study TFP growth, Canadian economy TFP growth and X-factor calculation 1993-2016[10]

Year	EGD TFP Growth	Canadian TFP Growth
	--------(percent)--------	
1993	1.22	1.11
1994	1.87	2.43
1995	-4.21	0.37
1996	7.04	-0.92
1997	-3.65	1.06
1998	-4.68	0.63
1999	3.35	2.38
2000	8.10	2.12
2001	-0.18	0.06
2002	-0.93	1.29
2003	6.78	-0.73
2004	-2.85	-0.32
2005	0.08	0.04
2006	-9.30	-0.82
2007	8.39	-1.14
2008	0.03	-2.30
2009	-2.78	-2.57
2010	-3.08	1.78
2011	3.56	1.49
2012	-10.33	-0.61
2013	9.33	0.91
2014	6.16	1.33
2015	-7.94	-1.00
2016	-11.07	*0.29*
Average	-0.21	0.29
X-Factor	-0.50	

[10] Source: EGD TFP growth: NERA EGD TFP Study, Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. I estimated Canadian TFP growth in 2016 using the average TFP growth for the time period 1993-2015 since Statistics Canada has not yet published a TFP number for this year.

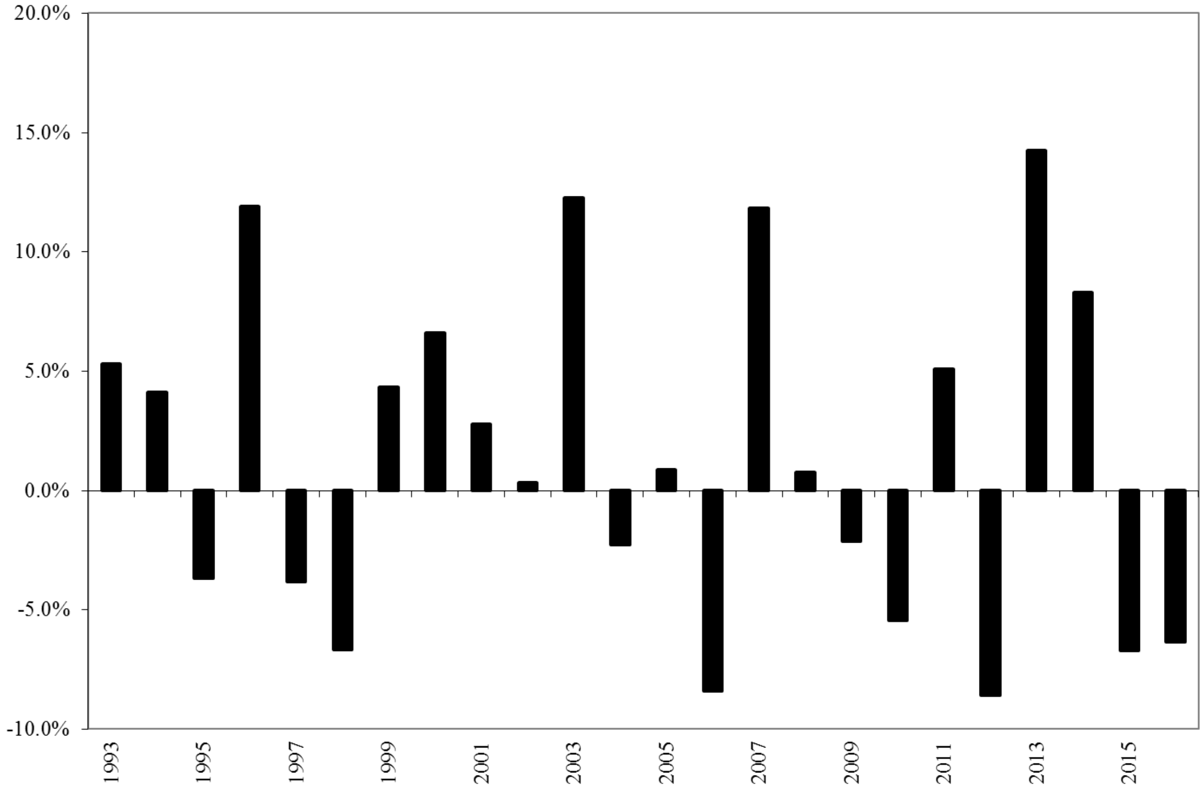
III. EGD Study Figures

Figure 1. EGD output shares, 1992-2016



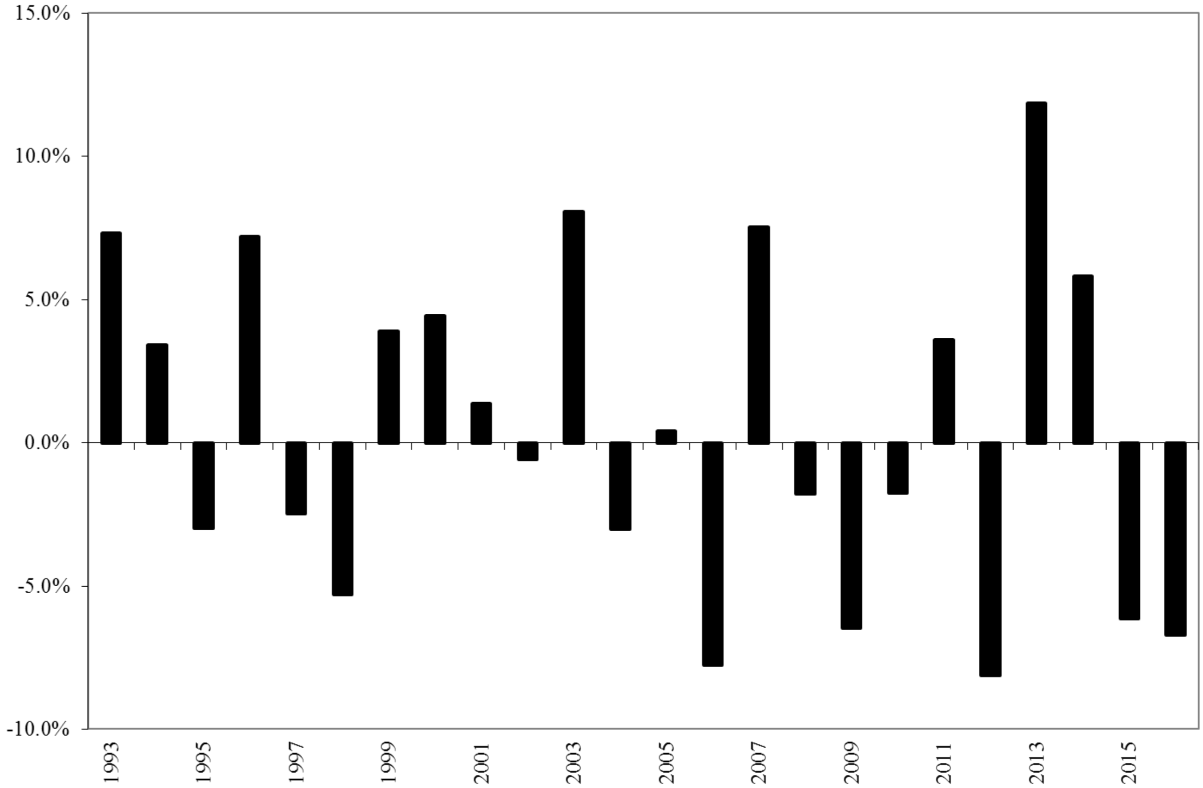
Source: NERA EGD TFP Study

Figure 2. EGD residential output index growth, 1993-2016



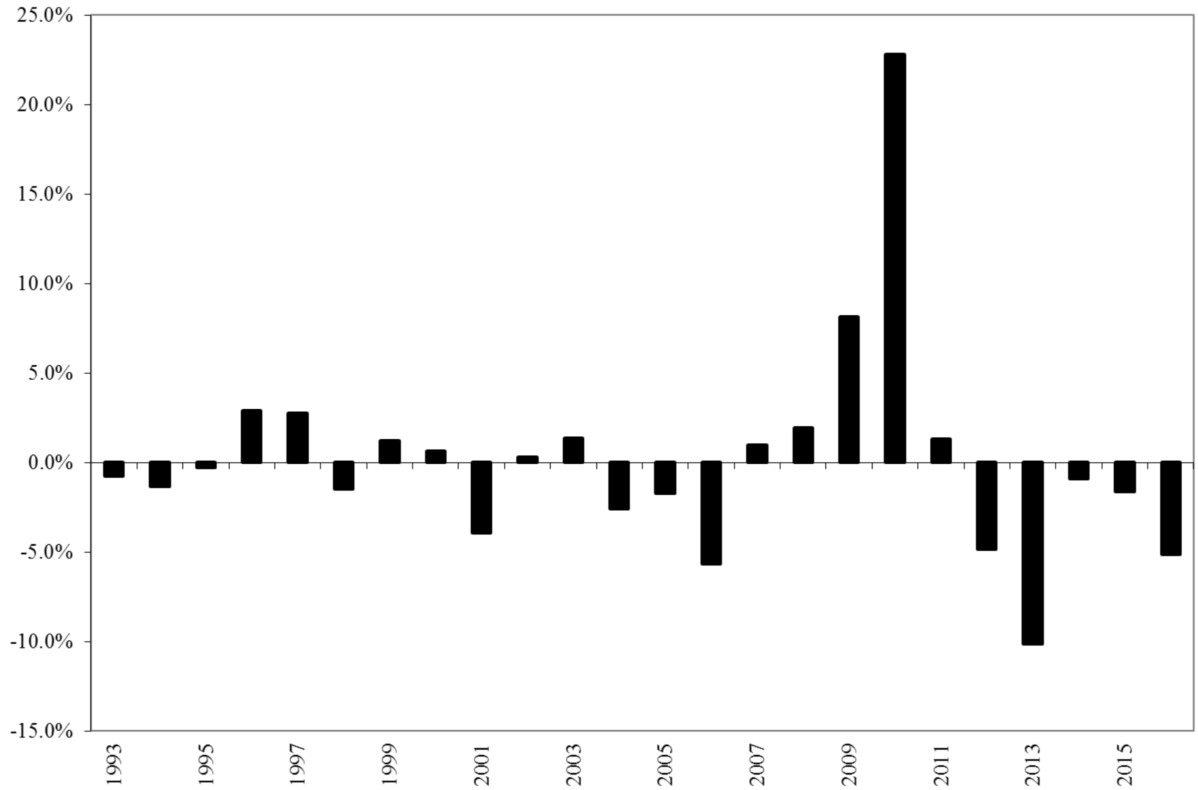
Source: NERA EGD TFP Study

Figure 3. EGD commercial output index growth, 1993-2016



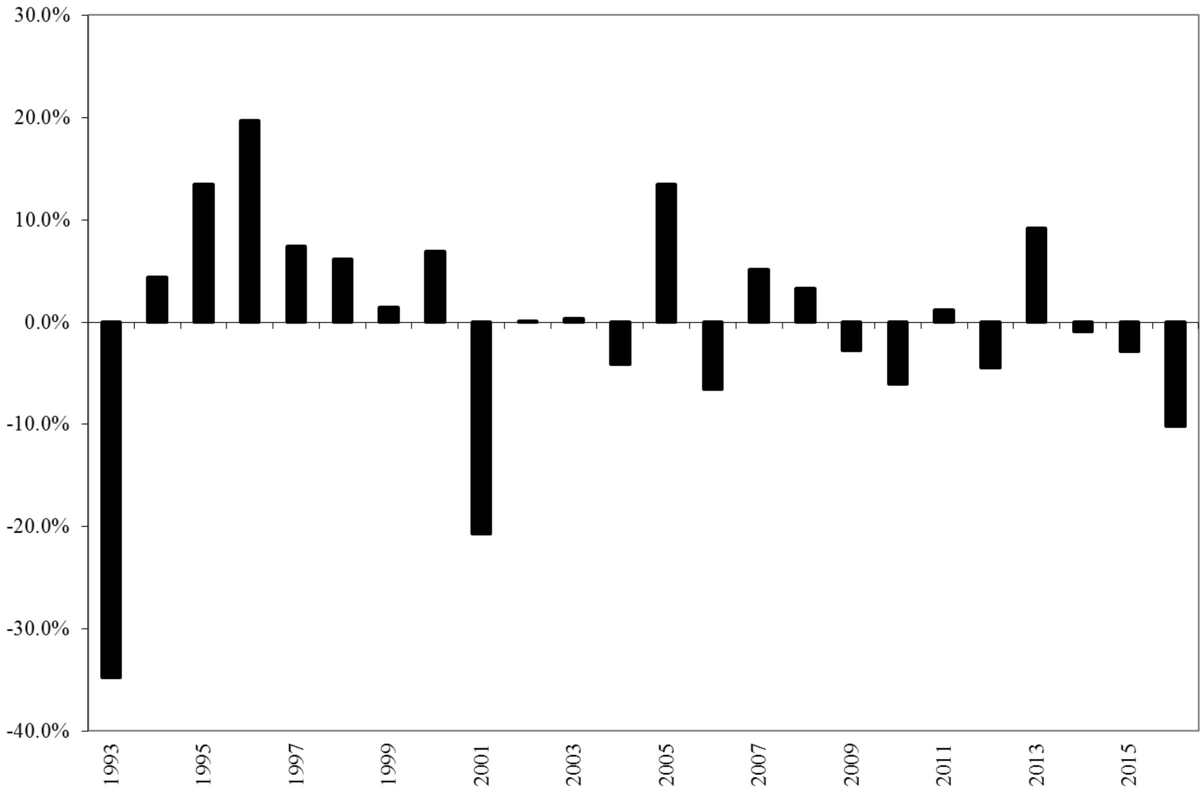
Source: NERA EGD TFP Study

Figure 4. EGD industrial output index growth, 1993-2016



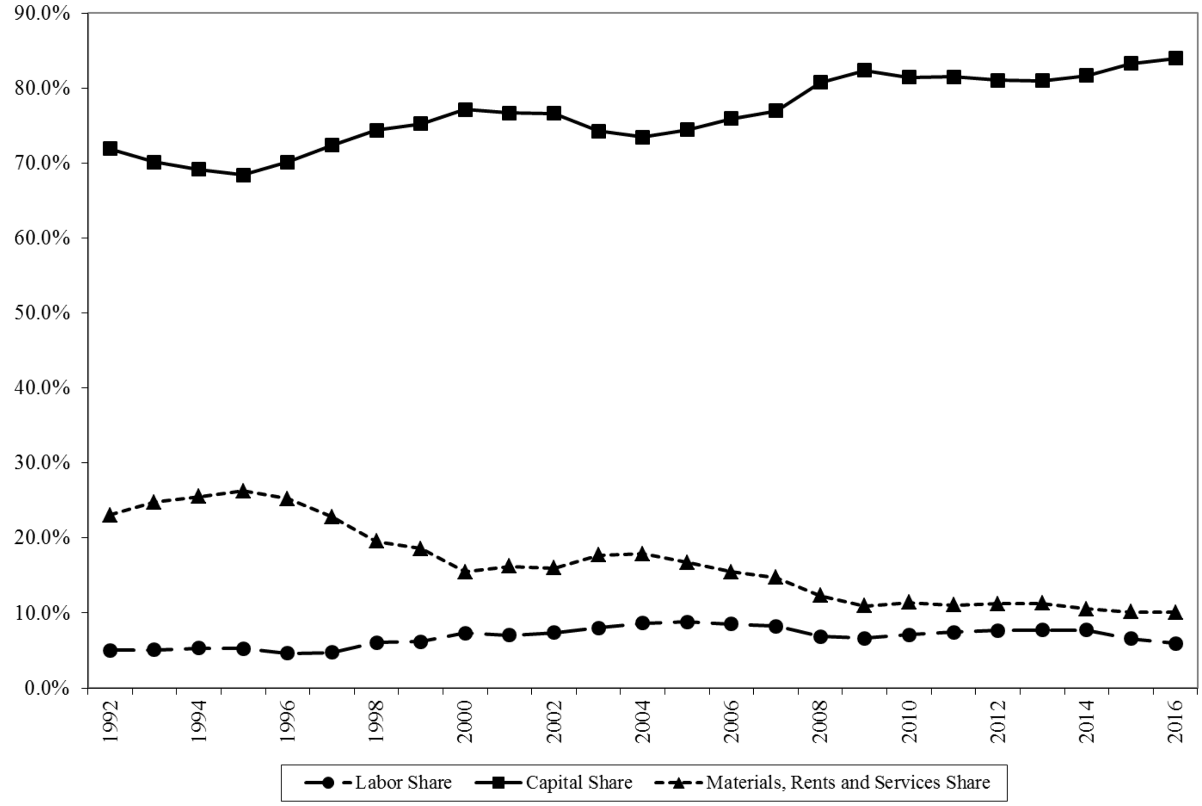
Source: NERA EGD TFP Study

Figure 5. EGD other (wholesale) output index growth, 1993-2016



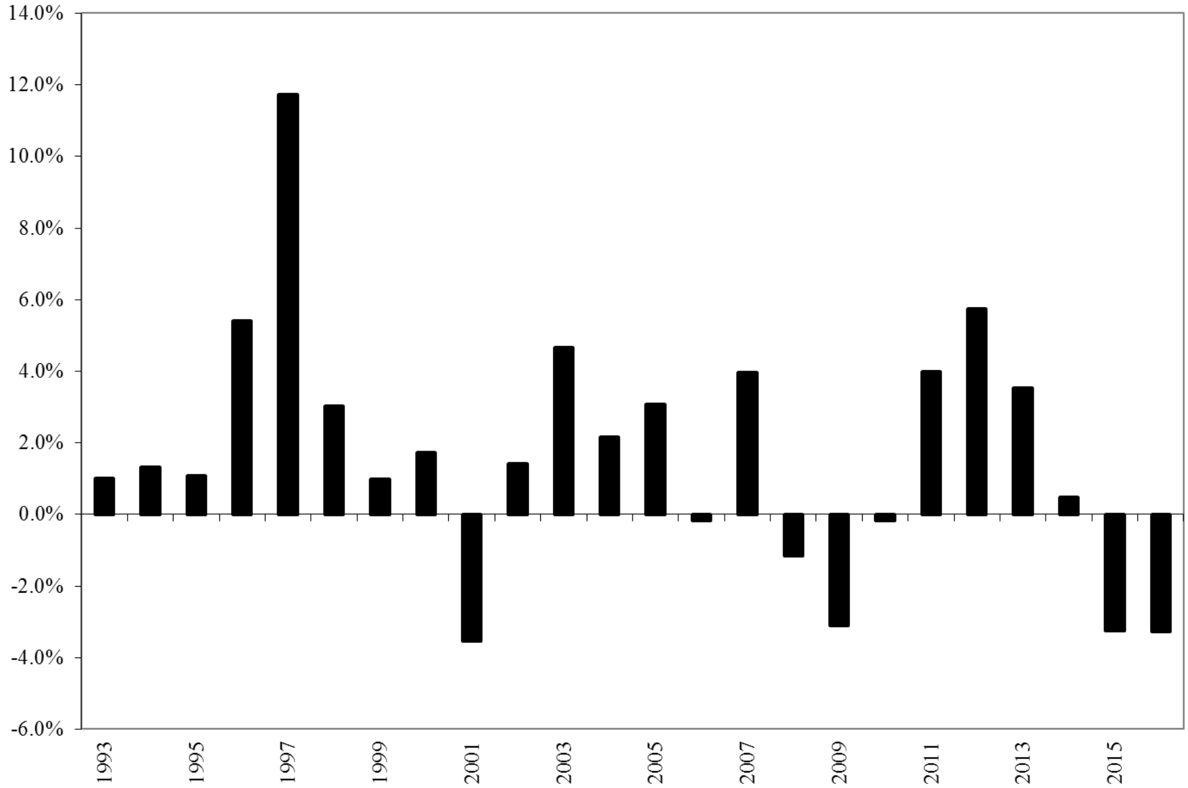
Source: NERA EGD TFP Study

Figure 6. EGD input Shares, 1992-2016



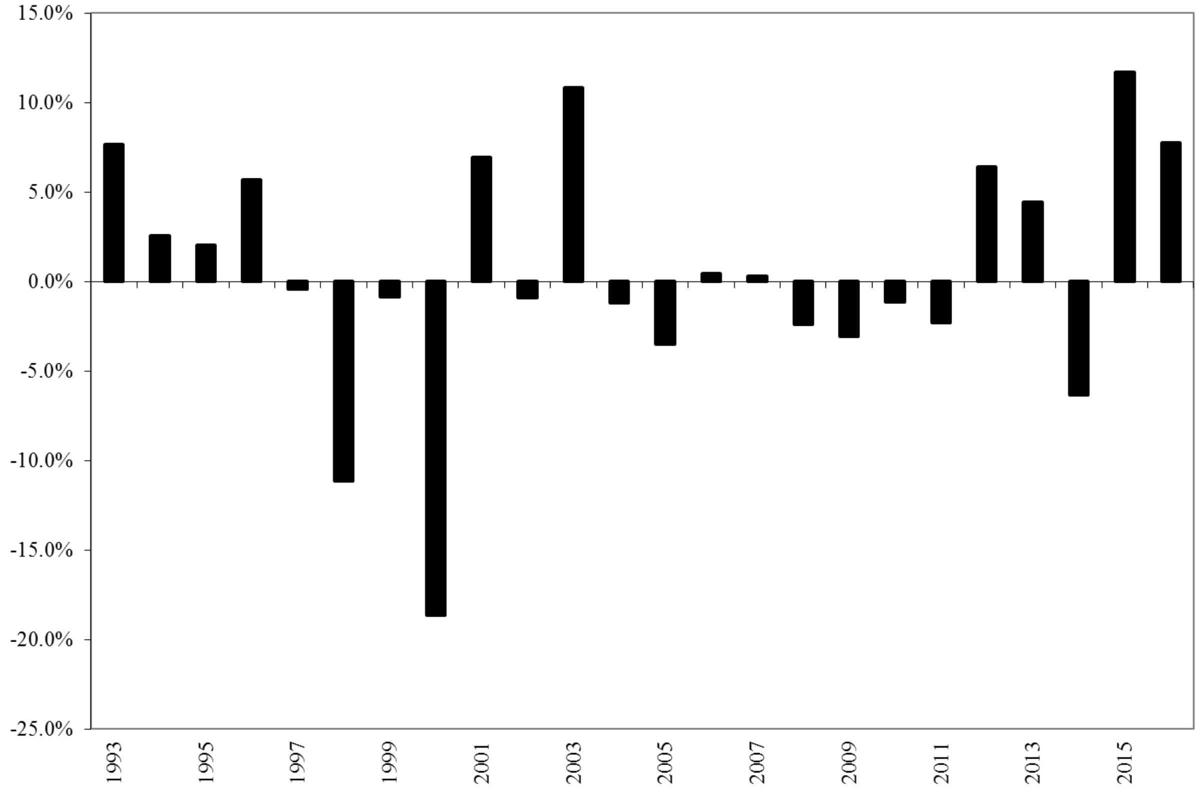
Source: NERA EGD TFP Study

Figure 7. EGD labor input index growth, 1993-2016



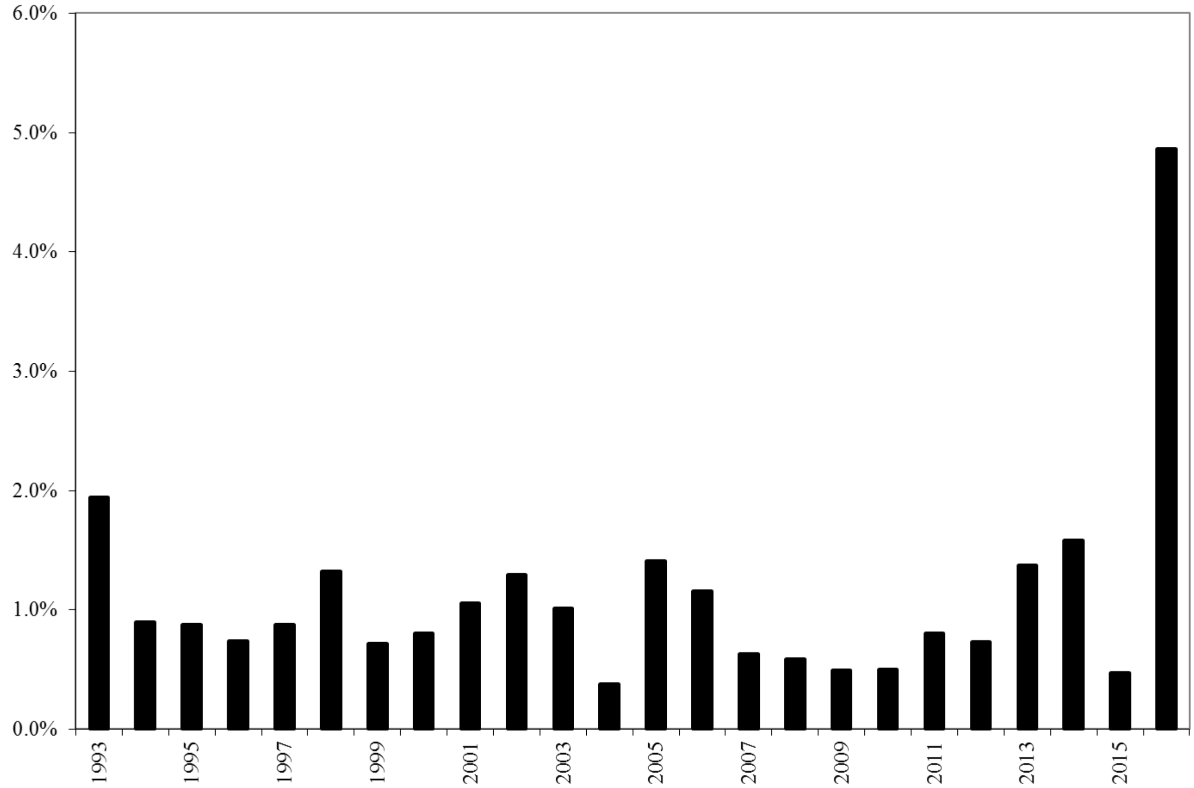
Source: NERA EGD TFP Study

Figure 8. EGD MRS input index growth, 1993-2016



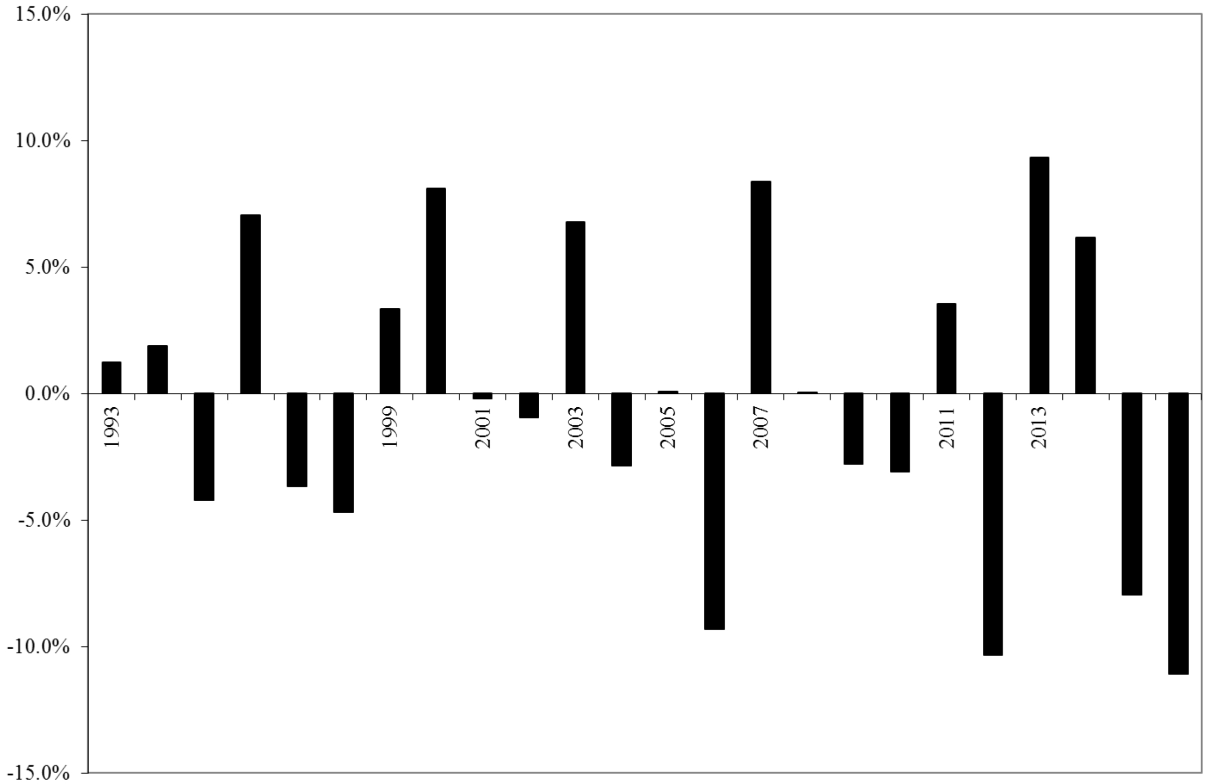
Source: NERA EGD TFP Study

Figure 9. EGD capital input index growth, 1993-2016



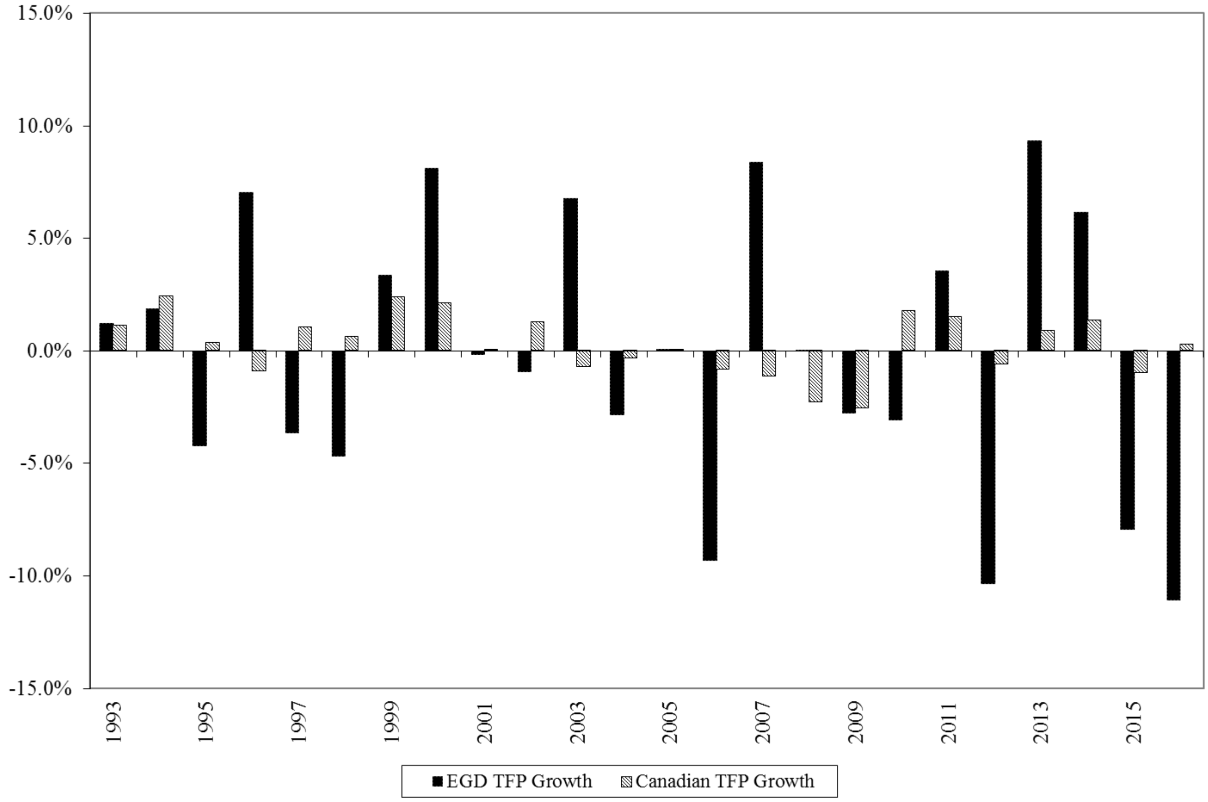
Source: NERA EGD TFP Study

Figure 10. EGD TFP growth, 1993-2016



Source: NERA EGD TFP Study

Figure 11. EGD TFP growth and Canadian economy TFP growth, 1993-2016



Source: NERA EGD TFP Study and Statistics Canada

Exhibit JDM-3, Tab 3: NERA Union Study Summary Tables and Figures

I. Union Study Tables

Table 1. Union TFP Study, output shares and output index growth, 2000-2016[11]

Service	Share of Output	Output Index Growth Rate
	(percent)	
General Service	81.97%	0.27%
Contract	18.03%	-0.88%

Table 2. Union TFP Study, input shares and input index growth, 2000-2016[12]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	8.58%	-0.42%
MRS	8.58%	1.40%
Capital	82.84%	-0.03%

[11] Source: NERA Union TFP Study, share of output and growth rates are unweighted.

[12] Source: NERA Union TFP Study, share of input and growth rates are unweighted.

Table 3. Union TFP Study, output, input and TFP growth, 2001-2016[13]

Year	Output growth	Input growth	TFP growth
	(percent)		
2001	-6.92	0.04	-6.89
2002	6.74	0.33	7.08
2003	3.82	1.61	5.43
2004	-4.24	-0.67	-4.91
2005	0.22	0.61	0.83
2006	-8.19	-0.04	-8.23
2007	6.96	0.00	6.96
2008	2.50	-0.17	2.33
2009	-4.10	0.11	-4.00
2010	-3.47	-0.60	-4.06
2011	6.42	-0.09	6.34
2012	-8.20	-0.09	-8.29
2013	12.29	0.23	12.52
2014	6.44	0.18	6.62
2015	-7.73	-0.57	-8.30
2016	-5.82	-1.32	-7.13
Average	-0.21	-0.03	-0.23

[13] Source: NERA Union TFP Study.

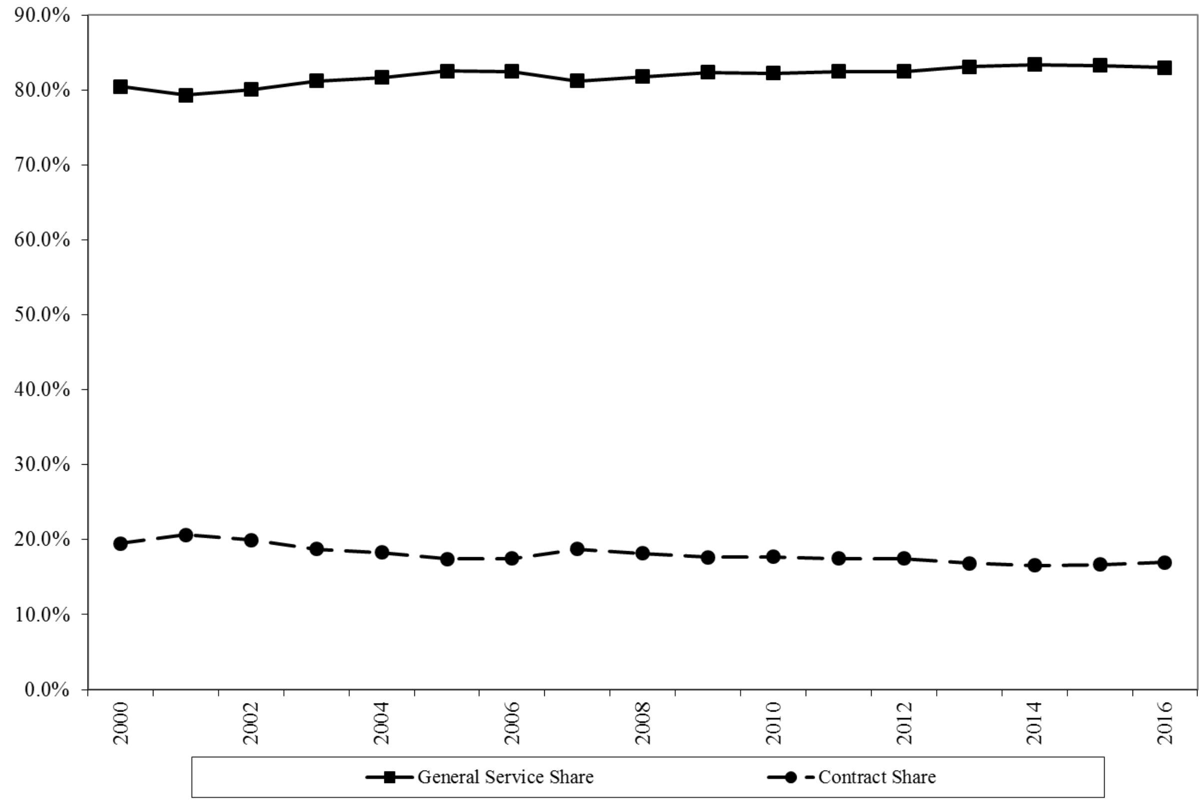
Table 4. Union Study TFP growth, Canadian economy TFP growth and X-factor calculation 2001-2016[14]

Year	Union TFP Growth	Canadian TFP Growth
	(percent)	
2001	-6.89	0.06
2002	7.08	1.29
2003	5.43	-0.73
2004	-4.91	-0.32
2005	0.83	0.04
2006	-8.23	-0.82
2007	6.96	-1.14
2008	2.33	-2.30
2009	-4.00	-2.57
2010	-4.06	1.78
2011	6.34	1.49
2012	-8.29	-0.61
2013	12.52	0.91
2014	6.62	1.33
2015	-8.30	-1.00
2016	-7.13	*-0.17*
Average	-0.23	-0.17
X-Factor	-0.06	

[14] Source: Union TFP growth: NERA Union TFP Study, Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. I estimated Canadian TFP growth in 2016 using the average TFP growth for the time period 1993-2015 since Statistics Canada has not yet published a TFP number for this year.

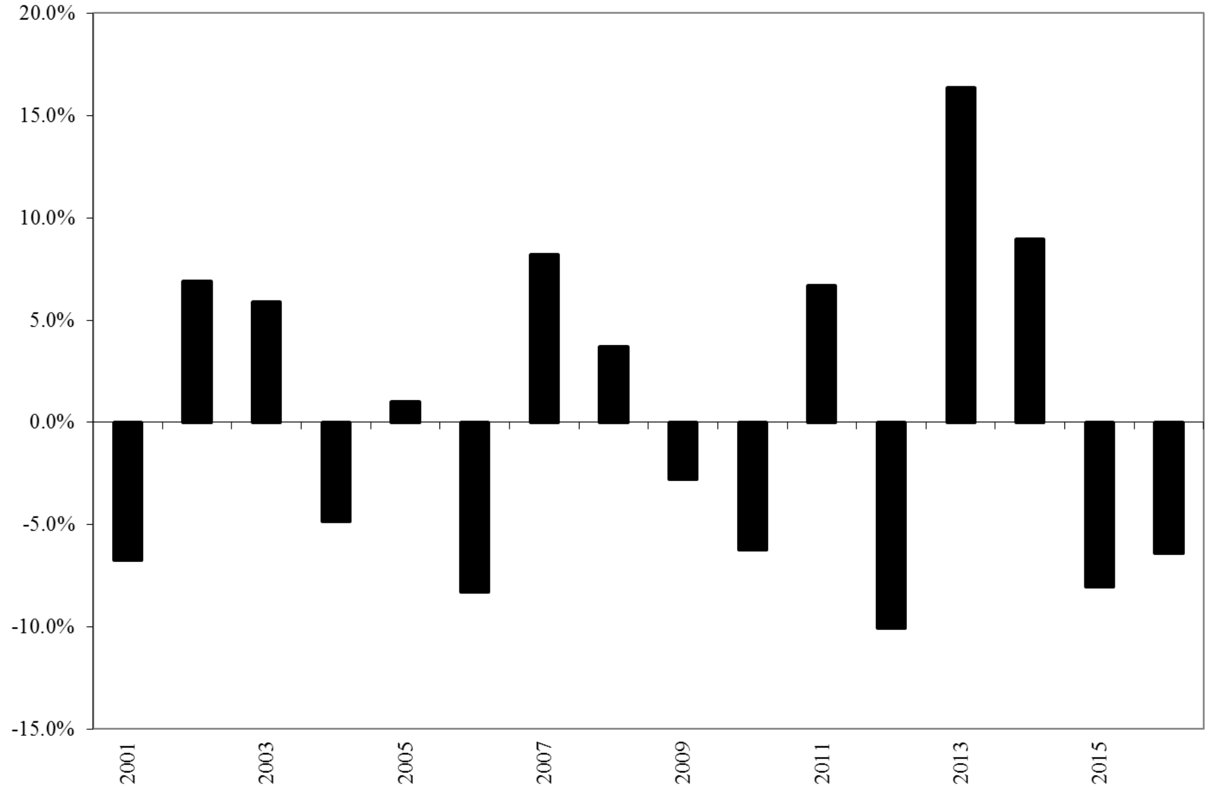
II. Union Study Figures

Figure 1. Union output shares, 2000-2016



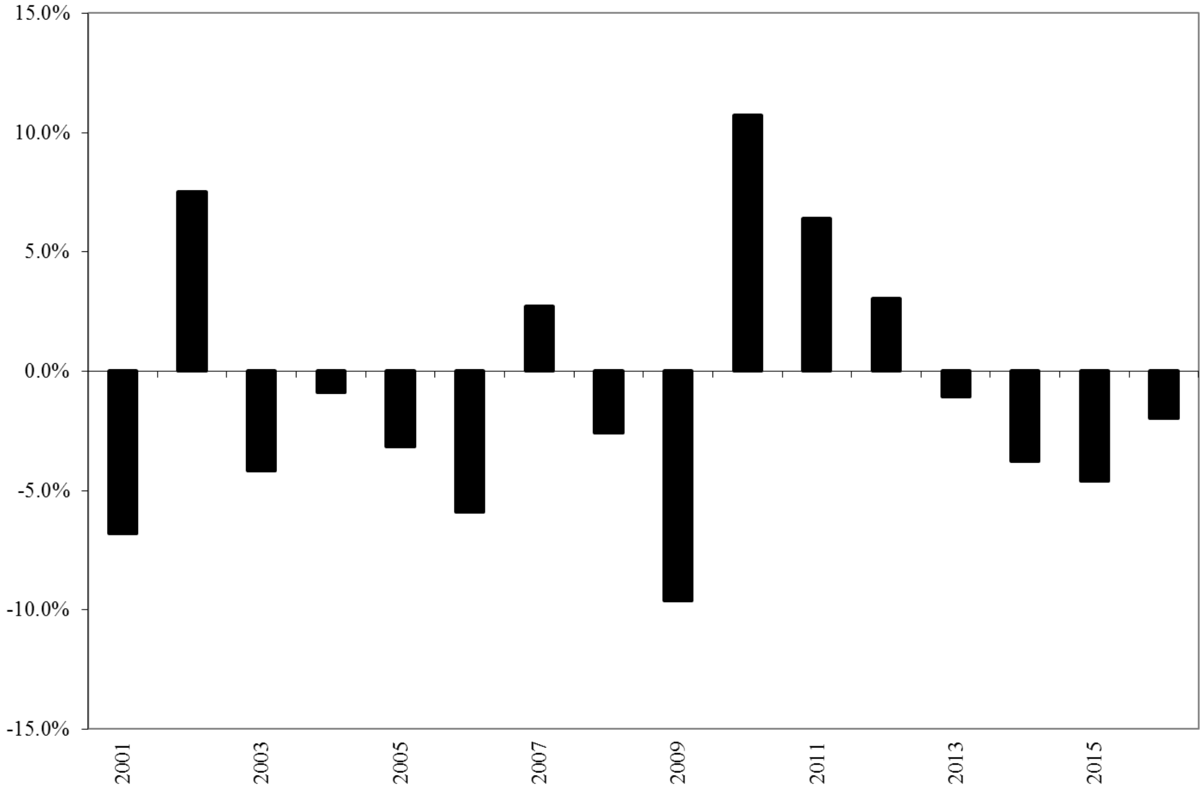
Source: NERA Union TFP Study

Figure 2. Union general service output index growth, 2001-2016



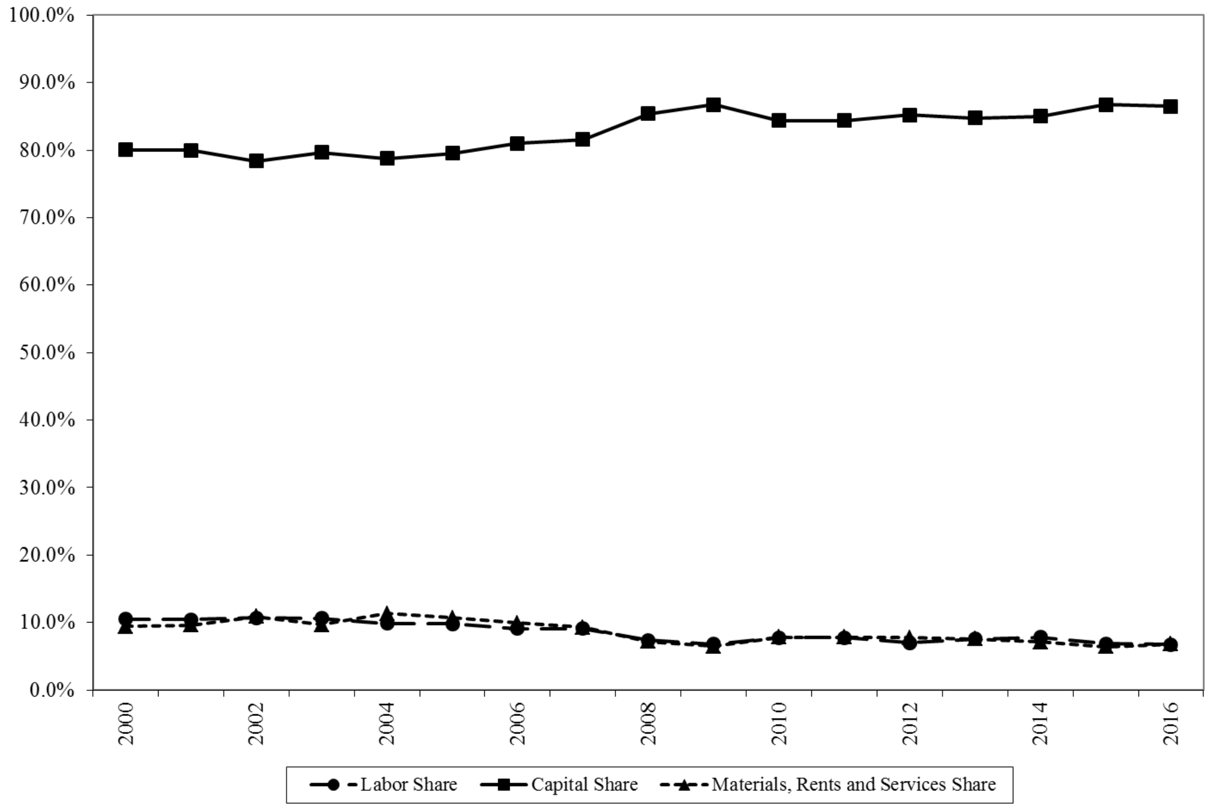
Source: NERA Union TFP Study

Figure 3. Union contract output index growth, 2001-2016



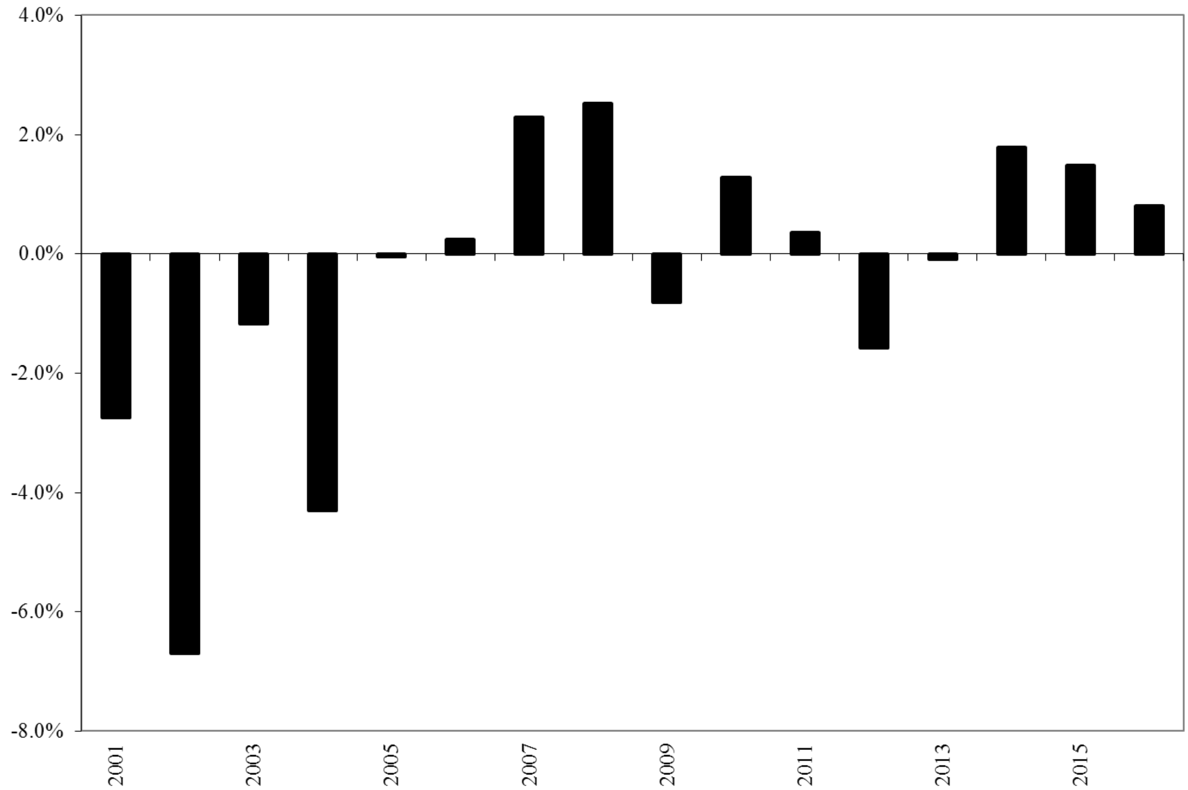
Source: NERA Union TFP Study

Figure 4. Union input shares, 2000-2016



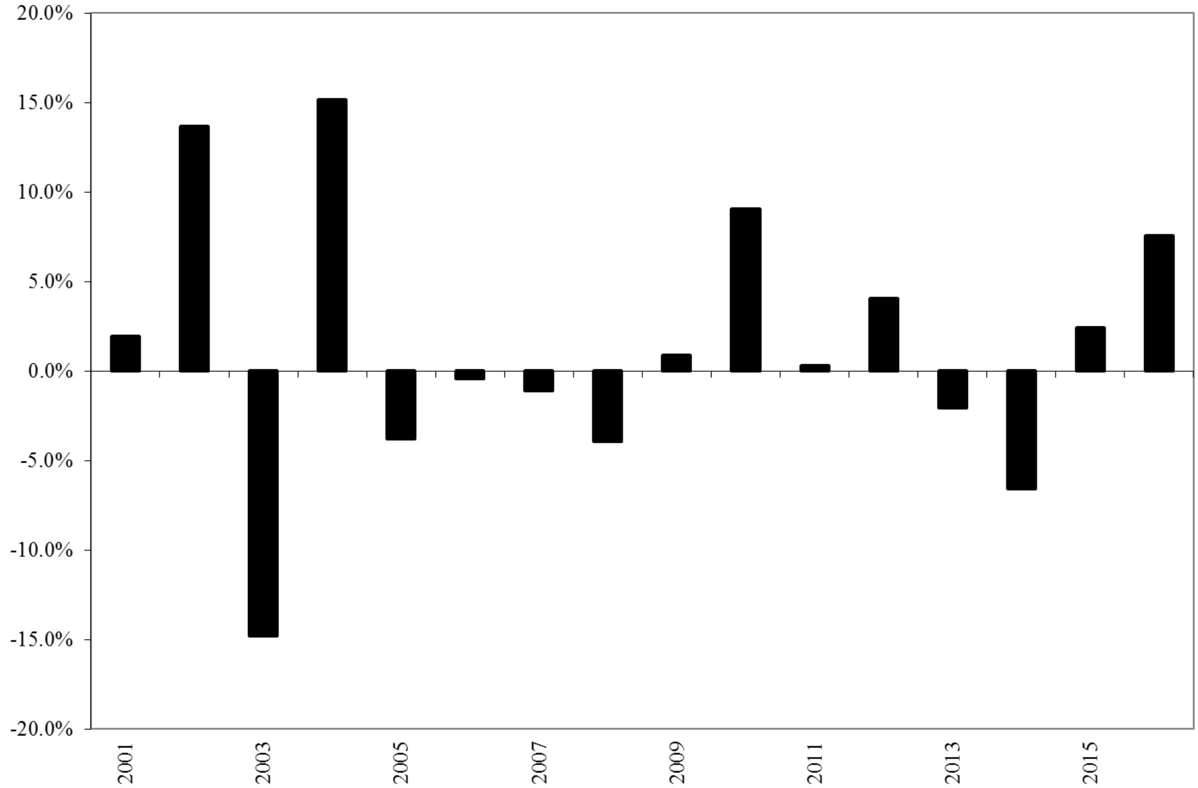
Source: NERA Union TFP Study

Figure 5. Union labor input index growth, 2001-2016



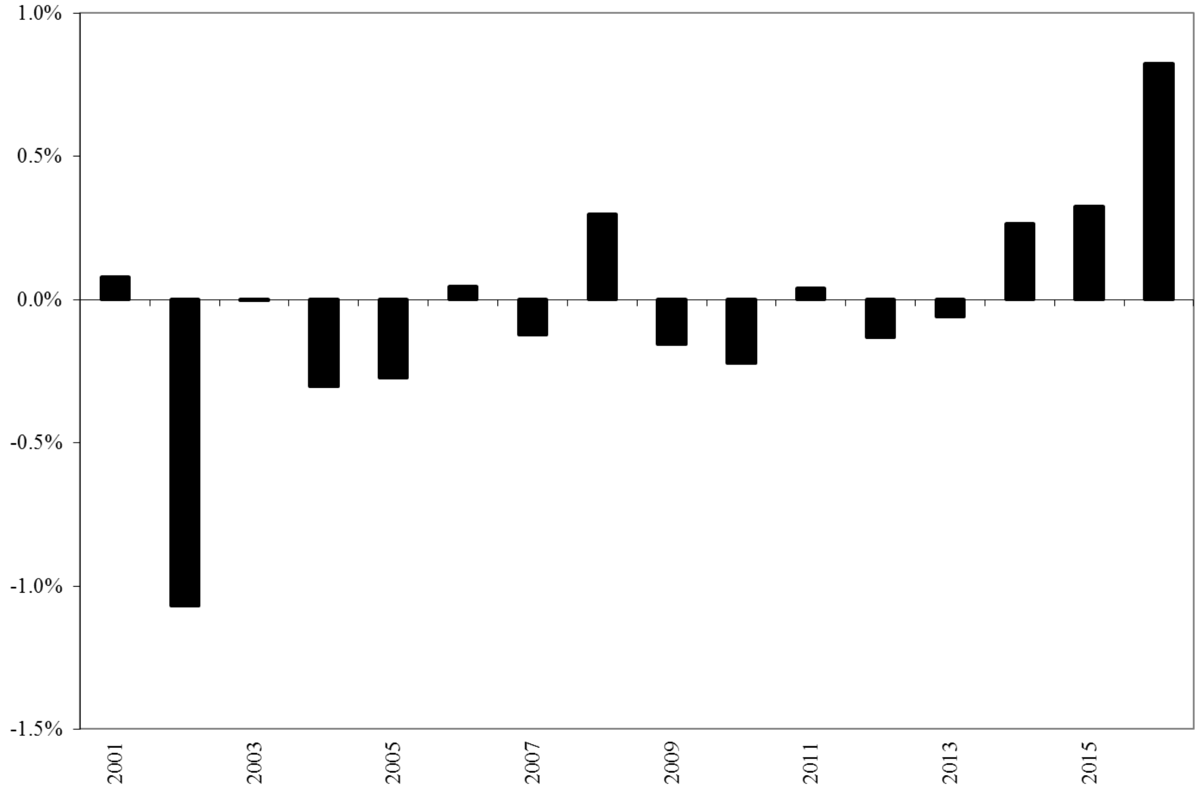
Source: NERA Union TFP Study

Figure 6. Union MRS input index growth, 2001-2016



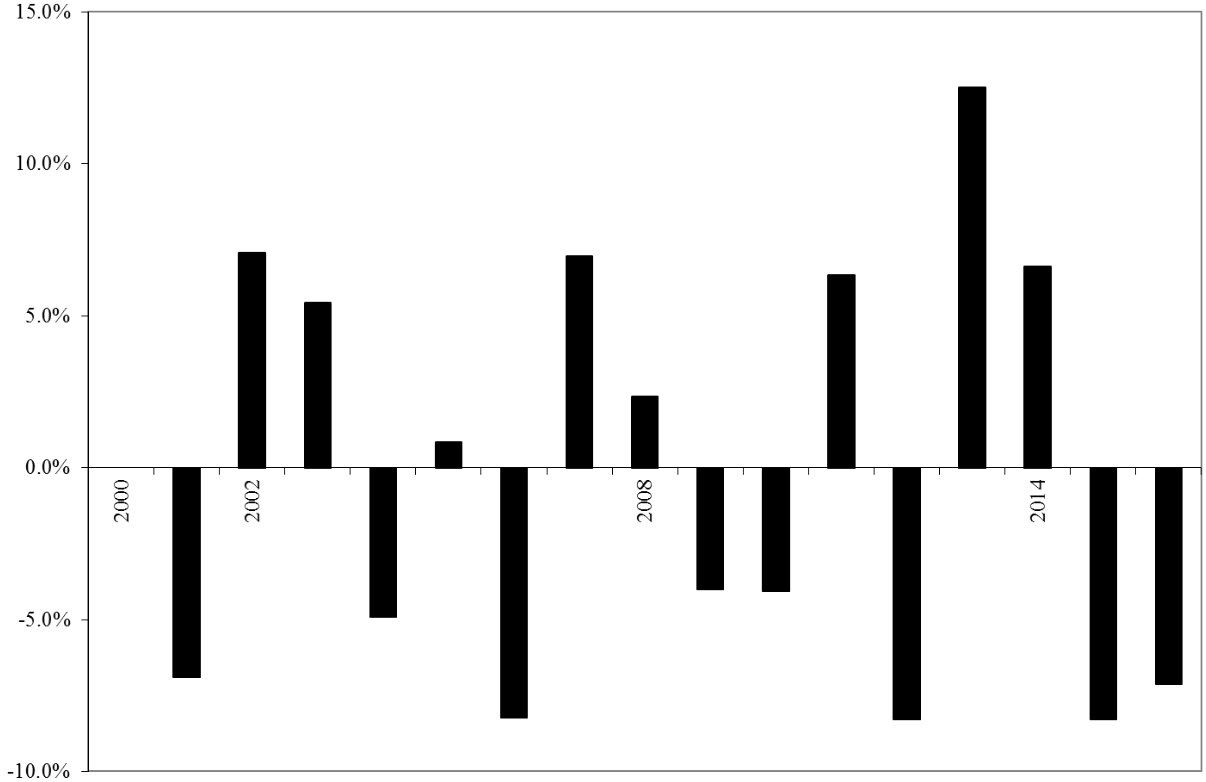
Source: NERA Union TFP Study

Figure 7. Union capital input index growth, 2001-2016



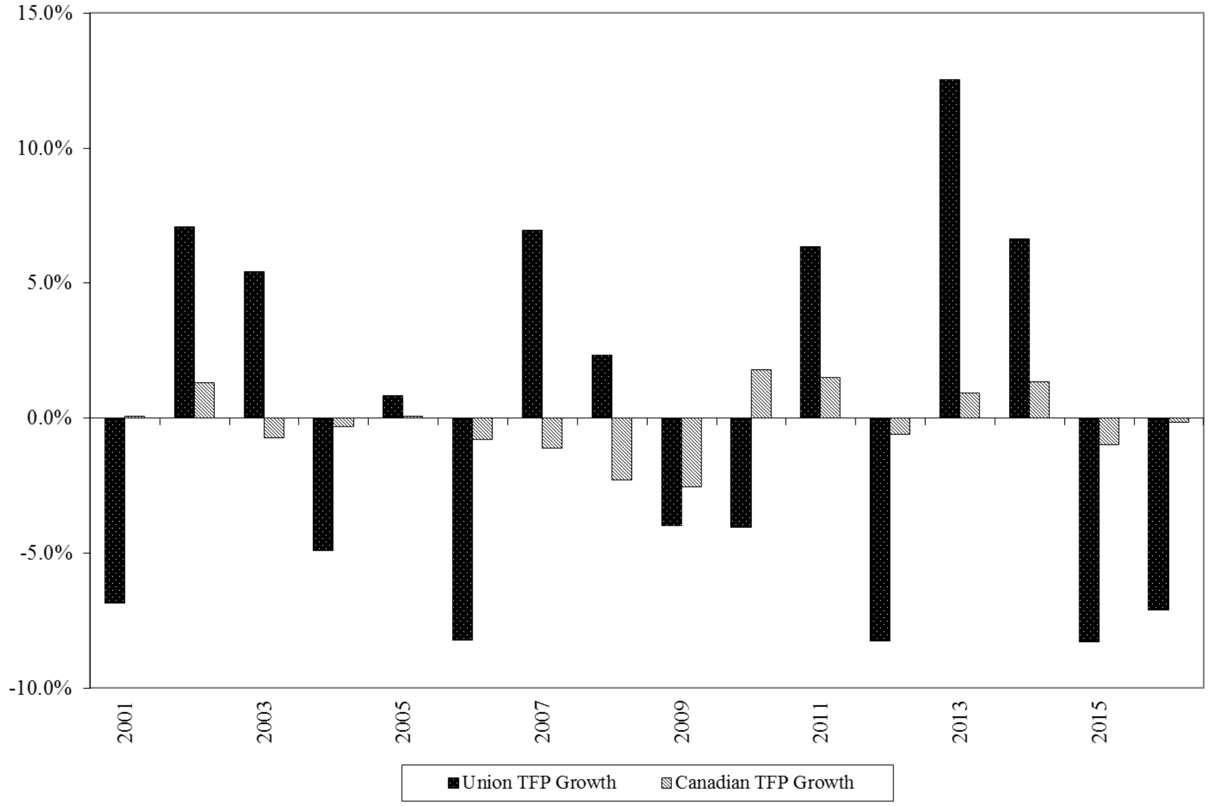
Source: NERA Union TFP Study

Figure 8. Union TFP growth, 2001-2016



Source: NERA Union TFP Study

Figure 9. Union TFP growth and Canadian economy TFP growth, 2001-2016



Source: NERA Union TFP Study and Statistics Canada

Exhibit JDM-4: Summary of Calculation of Input Price Differentials in Past Proceedings

I. Current Industry Study[1]

Year	Input price growth	US Input Price Growth
	(percent)	
1973	3.22	8.50
1974	8.14	5.40
1975	19.12	10.40
1976	11.96	9.20
1977	0.03	8.10
1978	6.62	8.60
1979	11.00	7.50
1980	13.80	6.60
1981	12.01	9.40
1982	3.78	4.10
1983	1.91	4.20
1984	5.25	7.30
1985	1.30	3.40
1986	9.41	2.10
1987	3.63	4.20
1988	-2.71	4.10
1989	6.01	4.20
1990	3.37	3.90
1991	2.41	1.40
1992	2.54	4.90
1993	5.87	2.10
1994	-0.47	2.00
1995	4.97	1.40
1996	0.41	3.40
1997	1.91	2.60
1998	5.42	1.90
1999	5.35	2.90
2000	5.57	3.60
2001	35.65	2.30
2002	-2.40	2.50
2003	-5.92	4.20
2004	-3.54	5.50
2005	5.11	4.70
2006	6.29	3.30
2007	8.56	3.50
2008	19.60	1.60
2009	8.21	-1.60
2010	-8.03	4.00
2011	1.59	2.30
2012	5.65	1.80
2013	0.28	2.30
2014	1.87	1.80
2015	8.67	1.20
2016	1.31	*4.11*
Average	5.34	4.11

t-statistic	Critical value (two-tail)	Degrees of freedom
1.1504	2.021	42

[1] Source: Industry Input Price Growth: NERA Industry TFP Study, Industry input price growth is weighted by total mWh; US Input Price Growth: U.S. Bureau of Labor Statistics (BLS), Net Multifactor Productivity and Cost (Private Business Sector), Table PG 4.3 available at: https://www.bls.gov/mfp/mprdload.htm. I estimate input price growth for the US economy in 2016, using the average input price growth for 1973-2015, since I did not have data for 2016 at the time of my analysis. The difference in means test encompasses the years 1973-2015.

II. Alberta Study[2]

Table 5. Study input price growth and U.S. and Canadian economy input price growth, 1973-2009[58]

Year	Input price growth(1)	U.S. input price growth	Canadian input price growth
		(percent)	
1973	3.03	8.35	10.40
1974	8.19	5.68	13.76
1975	19.55	10.65	9.26
1976	12.51	9.34	13.58
1977	-0.35	7.97	8.12
1978	6.52	8.32	6.58
1979	11.20	8.02	8.49
1980	13.82	6.92	7.69
1981	11.90	9.67	10.42
1982	4.08	2.90	6.53
1983	1.49	6.85	6.87
1984	5.29	6.76	6.61
1985	1.13	4.33	4.28
1986	9.75	3.91	1.57
1987	3.73	3.30	4.47
1988	-2.77	4.23	4.62
1989	5.94	4.08	3.21
1990	3.53	4.56	1.47
1991	2.38	2.64	0.13
1992	2.45	4.87	1.85
1993	5.84	2.41	2.50
1994	-0.68	2.81	3.53
1995	5.02	1.78	2.48
1996	0.16	3.60	0.60
1997	2.00	2.57	2.48
1998	5.22	2.63	0.20
1999	5.36	3.27	3.72
2000	0.31	3.87	6.41
2001	11.96	3.06	0.82
2002	11.96	4.02	1.61
2003	-6.16	4.75	2.80
2004	-4.41	5.44	2.49
2005	4.46	4.34	3.49
2006	6.10	3.76	1.93
2007	8.36	3.44	2.58
2008	20.60	2.29	1.86
2009	8.12	1.72	-4.34
Average	5.61	4.84	4.46

[58] Note: (1) Input price growth is weighted by total mWh. Input price growth for U.S. and Canadian economy are derived from: Economy-wide input price growth = GDP-PI growth + economy-wide TFP growth. Source: Input price growth: NERA; U.S. GDP-PI: Bureau of Economic Analysis, Table 1.1.9, *Implicit Price Deflators for Gross Domestic Product*, available at: http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=N, accessed on December 30, 2010; Canadian GDP-PI: Statistics Canada, Table 380-0056, *Implicit Chain Price Index Gross Domestic Product*, available for a fee at http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

[2] Taken from: "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," AUC Proceeding 566 – Rate Regulation Initiative, December 30, 2010, p. 22.

III. Central Maine Power Study[3]

APPENDIX 5

Comparison of U.S. Economy Input Price Growth with Northeast Power Distribution Input Price Growth

	U.S. Economy* (%)	Northeast Power Distribution** (%)
1973	8.3%	7.4%
1974	4.2%	20.2%
1975	9.4%	3.4%
1976	9.1%	1.9%
1977	8.6%	10.7%
1978	7.8%	10.6%
1979	8.2%	10.7%
1980	6.6%	12.5%
1981	9.9%	8.5%
1982	3.7%	5.2%
1983	5.6%	0.1%
1984	7.4%	7.0%
1985	4.0%	1.3%
1986	3.8%	1.9%
1987	3.1%	3.1%
1988	4.4%	5.7%
1989	4.1%	2.7%
1990	4.2%	3.3%
1991	2.9%	-0.3%
1992	5.1%	0.7%
Average 1972-1992:	6.0%	5.8%
t Statistic:	-0.168	
t Critical Value (two-tail)	2.093	

Note: The t-Statistic tests the assumption that the means of both time series are equal.

Sources: * Affidavit of Dr. Laurits R. Christensen on Behalf of the United States Telephone Association, CC Docket No. 94-1, February 1, 1995, Appendix A.
** Bureau of Labor Statistics, Average Hourly Earnings of Production Workers, Electric Services, Series ID: EEU42491006.
Standard & Poor's DRI, Operation and Maintenance Cost Model, Total Electric Distribution O&M Cost Index.
Standard & Poor's DRI, Operation and Maintenance Cost Model, Rental Price of Capital - Non Residential Structures - Public Utilities.
Ferc Form 1 Filings, 1972-1992.

---

[3] Taken from: Direct Testimony of Jeff D. Makholm, on behalf of Central Maine Power, in Docket No. 99-666 regarding Central Maine Power Company's Alternative Rate Plan (ARP2000), September 30, 1999, Appendix 5. Note that economy wide input price growth is measured for the US economy.

IV. UtilitCorp Networks Canada Study[4]

APPENDIX 6: COMPARISON OF INDUSTRY AND ECONOMY WIDE INPUT PRICE INDEXES

	Input Price Growth		
	Electricity Sector[1]	Total Economy[2]	Input Price Differential[3]
1973	8.07%	13.16%	-5.10%
1974	8.98%	13.97%	-4.99%
1975	5.51%	11.84%	-6.33%
1976	11.80%	11.16%	0.64%
1977	22.43%	7.54%	14.89%
1978	9.64%	8.00%	1.64%
1979	11.39%	10.47%	0.91%
1980	13.09%	9.94%	3.16%
1981	7.69%	5.83%	1.86%
1982	10.96%	4.56%	6.40%
1983	8.83%	8.82%	0.01%
1984	9.91%	7.09%	2.82%
1985	6.40%	5.48%	0.93%
1986	6.21%	1.59%	4.62%
1987	5.14%	5.79%	-0.65%
1988	6.20%	4.42%	1.77%
1989	-0.94%	3.13%	-4.08%
1990	-1.19%	0.74%	-1.92%
1991	8.95%	0.42%	8.53%
1992	3.44%	1.57%	1.87%
1993	-0.79%	1.97%	-2.76%
1994	1.54%	4.49%	-2.96%
1995	4.19%	3.80%	0.39%
average (72-95)	7.28%	6.34%	0.94%
standard deviation	5.26%	4.04%	4.76%

			95% confidence interval	
t-statistic	t critical value (two-tail)	degrees of freedom	high	low
0.950169131	2.07	22	10.80%	-8.92%

[1]Calculated by summing the growth rates of GDP-PI and MFP for the electric power systems industry. GDP-PI is calculated by dividing GDP in current dollars by GDP in constant dollars. For GDP Current Dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of Current Dollars, Business Sector, Electric Power Systems Industry, I193829 4763 8.35.129 (DOLLARS x 1M). For GDP Constant Dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of 1992 Constant Dollars, Business Sector, Electric Power Systems Industry, I196829 4767 8.35.129 (K DOLLARS x 1M). For MFP: Fisher Ideal Indices (1992=100) of Multifactor Productivity Based on Gross Output for Business Sector Industries, Annual, Electric Power Systems Industries, ID: I710309 9456 4.109 (INDEX).

[2]Calculated by summing MFP and GDP-PI growth indices for the Canadian Economy. For MFP: Fisher Ideal Indices (1992=100) of Multifactor Productivity Based on Real Value Added and Related Data for Business Sector and Selected Aggregates, Annual. Multifactor Productivity Business Sector, I720328 9458 1.1 (Index). GDP-PI is calculated by dividing GDP in current dollars by GDP in constant dollars.For GDP current dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of Current Dollars, Special Aggregations, Business Sector Industries, I195902 4766 2 (Dollars x 1M). For GDP current dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of 1992 Constant Dollars, Special Aggregations, Business Sector Industries, I198902 4770 2 (K Dollars x 1M).

[3]The difference between the electicity sector and total economy input price growths.

Note: All growth rates calculated using ln method: growth rate = ln(x/(x-1)).

[4] Taken from: Evidence of Jeff D. Makholm, on behalf of Utilicorp Networks Canada, on a Productivity Offset for a Proposed PBR Plan, September 1, 2000, Appendix 6. Note that economy wide input price growth is measured for the Canadian economy.

Materials Relied Upon

Industry TFP Growth Calculations:

- FERC Form 1
- Handy Whitman Index of Public Utility Construction Costs
- US IRS Form 1120
- Bloomberg Monthly Utility Bond Ratings
- Moody's Utility Bond Yields
- Bloomberg Fair Value Utility Yields
- Barclays Non-Utility Specific Index Bond Yields
- US Federal Reserve, US Treasury Securities 30 Year Constant Maturity Rate
- US Federal Reserve, US Consumer Price Index (CPI)
- US Bureau of Economic Analysis, US Gross Domestic Product Price Index (GDP-PI), Table 1.1.4
- US Bureau of Labor Statistics, US Input Price Growth, Net Multifactor Productivity and Cost (Private Business Sector), Table PG 4.3
- Statistics Canada, Canadian Multifactor Productivity (MFP) for the Business Sector, Table 383-0021

EGD TFP Growth Calculations:

- Handy Whitman Index of Public Utility Construction Costs
- Statistics Canada, Canadian Gross Domestic Product Price Index (GDP-PI), Table 380-0102
- US Federal Reserve, Canadian Long-Term Government Bond Yields, 10 year main (including Benchmark)
- Statistics Canada, Canadian Consumer Price Index (CPI), Table 326-0020
- Revenue Canada, T2 Corporation Income Tax Guide (1990-2016)
- Statistics Canada, Canadian Multifactor Productivity (MFP) for the Business Sector, Table 383-0021
- Bloomberg Enbridge Gas Distribution Monthly Utility Bond Ratings
- Moody's Utility Bond Yields
- Bloomberg Fair Value Utility Yields
- Barclays Non-Utility Specific Index Bond Yields
- EBRO 485, Exhibit D5, Tab 9, Schedule 2, p. 1
- EBRO 487, Exhibit D5, Tab 9, Schedule 2, p. 1
- EBRO 490, Exhibit D5, Tab 10, Schedule 2, p. 1
- EBRO 492, Exhibit D5, Tab 10, Schedule 2, p. 1
- EBRO 495, Exhibit D5, Tab 10, Schedule 2, p. 1
- EBRO 497, EBO 170-14, Exhibit D5, Tab 9, Schedule 2, p. 1
- EBRO 485, Exhibit D5, Tab 4, Schedule 2, p. 1
- EBRO 487, Exhibit D5, Tab 4, Schedule 2, p. 1
- EBRO 490, Exhibit D5, Tab 4, Schedule 2, p. 1
- EBRO 492, Exhibit D5, Tab 4, Schedule 2, p. 1
- EBRO 495, Exhibit D5, Tab 4, Schedule 2, p. 1

- EBRO 497, EBO 170-14, Exhibit D5, Tab 4, Schedule 2, p. 1
- EBRO 485, Exhibit D5, Tab 3, Schedule 2, p. 2
- EBRO 487, Exhibit D5, Tab 3, Schedule 2, p. 2
- EBRO 490, Exhibit D5, Tab 3, Schedule 2, p. 2
- EBRO 492, Exhibit D5, Tab 3, Schedule 2, p. 3
- EBRO 495, Exhibit D5, Tab 3, Schedule 2, p. 3
- EBRO 497, EBO 179-14, Exhibit D5, Tab 3, Schedule 2, p. 2
- RP-1999-0001, Exhibit D5, Tab 1, Schedule 2, p. 1
- RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4
- RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4
- RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4
- RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4
- RP-2003-0203, Exhibit D3, Tab 4, Schedule 1, p. 2
- EB-2005-0001, Exhibit A6, Tab 1, Schedule 1, p. 12
- EB-2006-0034, Exhibit D1, Tab 1, Schedule 1, p. 1
- EB-2008-0219, Exhibit D, Tab 3, Schedule 1, p. 1
- EB-2009-0055, Exhibit B, Tab 4, Schedule 2, p. 1
- EB-2010-0042, Exhibit B, Tab 4, Schedule 2, p. 1
- EB-2011-0008, Exhibit B, Tab 4, Schedule 2, p. 1
- EB-2011-0354, Exhibit D1, Tab 3, Schedule 1, p. 11
- EB-2013-0046, Exhibit B, Tab 4, Schedule 2, p. 1
- EB-2012-0459, Exhibit D1, Tab 3, Schedule 1, p. 27
- EB-2015-05-0122, Exhibit B, Tab 4, Schedule 2, p. 1
- EB-2016-0142, Exhibit B, Tab 4, Schedule 2, p. 1

- EB-2017-0102, Exhibit B, Tab 4, Schedule 2, p. 1
- EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4
- EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4
- EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4
- EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4
- EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4
- EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3
- RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3
- RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3
- RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3
- RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3
- RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3
- EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3
- EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3
- EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3
- EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3
- EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3
- EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3
- EGD output volumes (including the effect of the DSM program) (1992-2016)

- EGD full-time equivalent employees (2000-2016)
- EGD wages and salaries (2000-2016)
- EGD gross and net capital (1992-2016)
- EGD capital additions and retirements (1992-2016)

Union TFP Growth Calculations:

- Handy Whitman Index of Public Utility Construction Costs
- Statistics Canada, Canadian Gross Domestic Product Price Index (GDP-PI), Table 380-0102
- US Federal Reserve, Canadian Long-Term Government Bond Yields, 10 year main (including Benchmark)
- Statistics Canada, Canadian Consumer Price Index (CPI), Table 326-0020
- Revenue Canada, T2 Corporation Income Tax Guide (2000-2016)
- Statistics Canada, Canadian Multifactor Productivity (MFP) for the Business Sector, Table 383-0021
- Bloomberg Union Gas Limited Monthly Utility Bond Ratings
- Moody's Utility Bond Yields
- Bloomberg Fair Value Utility Yields
- Barclays Non-Utility Specific Index Bond Yields
- EB-2005-0520, Exhibit G3, Tab 2, Schedule 1, Page 1, Updated for Board Decision
- EB-2011-0210, Exhibit G3, Tab 2, Schedule 1, Page 1, Updated for Board Decision
- EB-2005-0520, Exhibit G3, Tab 3, Schedule 3, Pages 1-3, Updated for Board Decision
- EB-2011-0210, Exhibit G3, Tab 3, Schedule 3, Pages 1-4, Updated for Board Decision
- Union output volumes (including the effect of the DSM program) (2000-2016)
- Union revenues (2000-2016)
- Union wages and salaries (2000-2016)
- Union full-time equivalent employees (2000-2016)
- Union operations & maintenance expense (2000-2016)
- Union gross and net capital (2000-2016)
- Union capital additions and retirements (2000-2016)

Testimony and Exhibits References:

- Makholm, *The Political Economy of Pipelines*, University of Chicago Press, Chicago and London (2012)
- Makholm, "Electricity Deregulation under Siege," *Natural Gas and Electricity*, Volume 34, No. 5 (August 2017)
- Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom, *The Rand Journal of Economics,* Vol. 20,No. 3 (1989)
- Alberta Utilities Commission (AUC) Proceeding 566, AUC, Decision 2012-237, September 12, 2012
- Littlechild, S.C., "Regulation of British Telecommunications' Profitability," London: Department of Industry, (1983)
- Makholm, "Utility Regulation Principles Vary Widely Country to Country," Natural Gas and Electricity, Volume 32, Issue 5 (December 2015)
- Makholm, J., and Gordon, K., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," NERA Working Paper prepared for the Canadian Gas Association, February, 2008
- Ofgem, "RIIO: A new way to regulate energy networks," Final decision, October 2010
- FCC 95-132, CC Docket No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," 1989
- California Public Utilities Commission (CPUC), Decision D.89-10-031), 1989
- Massachusetts Department of Public Utilities (DPU), New Eng. Tel. & Tel. Co. dba NYNEX, D.P.U. 94-50, May 12, 1995
- Kahn, A.E., *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness*, MSU Public Utility Papers, Michigan State University, East Lansing (1998)
- Makholm. J.D., Sources of Total Factor Productivity in the Electric Utility Industry, Unpublished Ph.D. Dissertation, University of Wisconsin-Madison, 1986
- Ontario Energy Board, Decision with Reasons RP-1999-0034
- Ontario Energy Board, Decision with Reasons in RP-1999-0017

- RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005
- Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006
- Ontario Energy Board, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008
- Ontario Energy Board, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008
- Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012
- Ontario Energy Board, Report of the Board Rate Setting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors, EB-2010-0379, December 4, 2013
- Alberta Utilities Commission, Decision 201414, December 16, 2016
- Makholm, "Elusive Efficiency and the X-factor in Incentive Regulation: The Törnqvist v. DEA/Malquist Dispute," in Voll, S.P., and King, M.K. (Eds.), *The Line in the Sand: The Shifting Boundaries Between Markets and Regulation in Network Industries*, National Economic Research Associates, White Plains, New York (2007)
- "Regulating Utility Efficiency "Fast and Slow": the Current Australian Problem, *Natural Gas and Electricity*, Volume 34, No. 5 (October 2017)
- Ontario Energy Board, Decision EB-2007-0615, Schedule A, Enbridge Gas Distribution Revised Settlement Agreement
- Ontario Energy Board, Decision EB-2007-0606, Schedule A, Union Gas Settlement Agreement
- Ontario Energy Board, Decision EB-2013-0202, October 7, 2013
- Ontario Energy Board, Decision EB-2012-0459, July 17, 2014
- Charnes, A., Cooper, W.W., and Rhodes, E., Measuring the Efficiency of Decision Making Units," European Journal of Operational Research, Vol. 2 (1978)
- Sena, V., "The Frontier Approach to the Measurement of Productivity and Technical Efficiency," Economic Issues, Vol. 8, Part 2 (2003)

- Borenstein S., and Bushnell, J., "The U.S. Electricity Industry after 20 Years of Restructuring," Energy Institute at Haas Working Paper (May 2015)

- NERA Report in AUC Proceeding 566- Rate Regulation Initiative, "Total Factor Productivity Study for Use in AUC Proceeding 566-Rate Regulation Initiative, December 30, 2010

- Direct Testimony of Jeff D. Makholm, on behalf of Central Maine Power, in Docket No. 99-666 regarding Central Maine Power Company's Alternative Rate Plan (ARP2000), September 30, 1999

- Evidence of Jeff D. Makholm, on behalf of Utilicorp Networks Canada, on a Productivity Offset for a Proposed PBR Plan, September 1, 2000

- *Northwestern Utilities v. City of Edmonton, S.C.R. 186 (NUL 1929)*

- *Federal Power Commission et al v. Hope Natural Gas Co, 320 U.S. 591 (1944)*