Incentive Plan Design for Ontario's Gas Utilities

Dr. Mark Newton Lowry, *Partner*
Pacific Economics Group, LLC

Toronto, ON
3 November 2006

Pacific Economics Group
Economic and Litigation Consulting

Introduction

The Ontario Energy Board ("OEB") is developing incentive regulation ("IR") plans for the province's gas utilities

- Enbridge Gas Distribution
- Union Gas

This presentation addresses some key plan design issues

- Useful grounding for stakeholders
- Preliminary research results

Plan of Presentation

Rebasing Rules

Price Cap Index Design

- **X Factor Calibration**
- **Inflation Factor**
- **Stretch Factor**

Accommodations for Major Plant Additions

Rebasing Rules

Motivation

Rebasing rules address the calculation of castoff rates at the end of the IR plan period

These rules affect incentives for

- Long term performance gains
- Opportunistic timing of maintenance & capital spending

Rebasing rule reform is important focus of recent IR innovation

Precedents

<u>Victoria's "Efficiency Carryover Mechanism"</u>

Victoria's Essential Services Commission is PBR innovator

Adapted "rolling incentives" mechanism developed by Britain's OFWAT for power distribution

- Savings = Approved budget – Actual cost
- Utilities get to keep some of savings for five years
  --- even in the *later* plan years
- Applied initially to capex & opex
  currently to opex

National Grid USA (MA)

Massachusetts DTE approved ten year rate plan for power distribution services of National Grid

In last plan year (2009) …

$$\text{Earned Savings} = (\text{Revenue} - \text{Cost})^{\text{After Tax}}$$

Rates include…

100% of Earned Savings up to cap of $43 million +
60% of any surplus up to a cap of $ 60 million

… for ten years

National Grid USA (cont'd)

"The full recognition and recovery of Earned Savings following the Rate Plan Period and in a defense to a complaint during the period of the Rate Plan are the central considerations and inducements for Mass Electric to enter into this Settlement and to commit to the long term obligations and rate reductions included in the rate plan"[1]

Rate Plan Settlement, Docket D.T.E. 99-47, November 1999

Rebasing Rules (cont'd)

Innovative Rules Under Consideration

1. "Partial Plan Update"

Rates at start of next plan based

80% on traditional rate case

20% on 1 year extension of expiring rate adjustment mechanism

Pacific Economics Group
Economic and Litigation Consulting

Rebasing Rules (cont'd)

Innovative Rules Under Consideration

2. Rate Options Plan

Utility has option on castoff rates for next plan that reflect

- Actual input price growth
- X% productivity growth

even if cost of service is lower

Variant: "Keepable" $\text{Cost}^{\text{Allowed}} - \text{Cost}^{\text{Actual}}$ can be capped

Incentive Power Results

PEG's incentive power research helps identify good rebasing rules

Research Methodology

Define decision problem of hypothetical utility under alternative, concrete regulatory systems

Determine "optimal" strategy using numerical analysis

Calculate impact on performance, earnings, rates

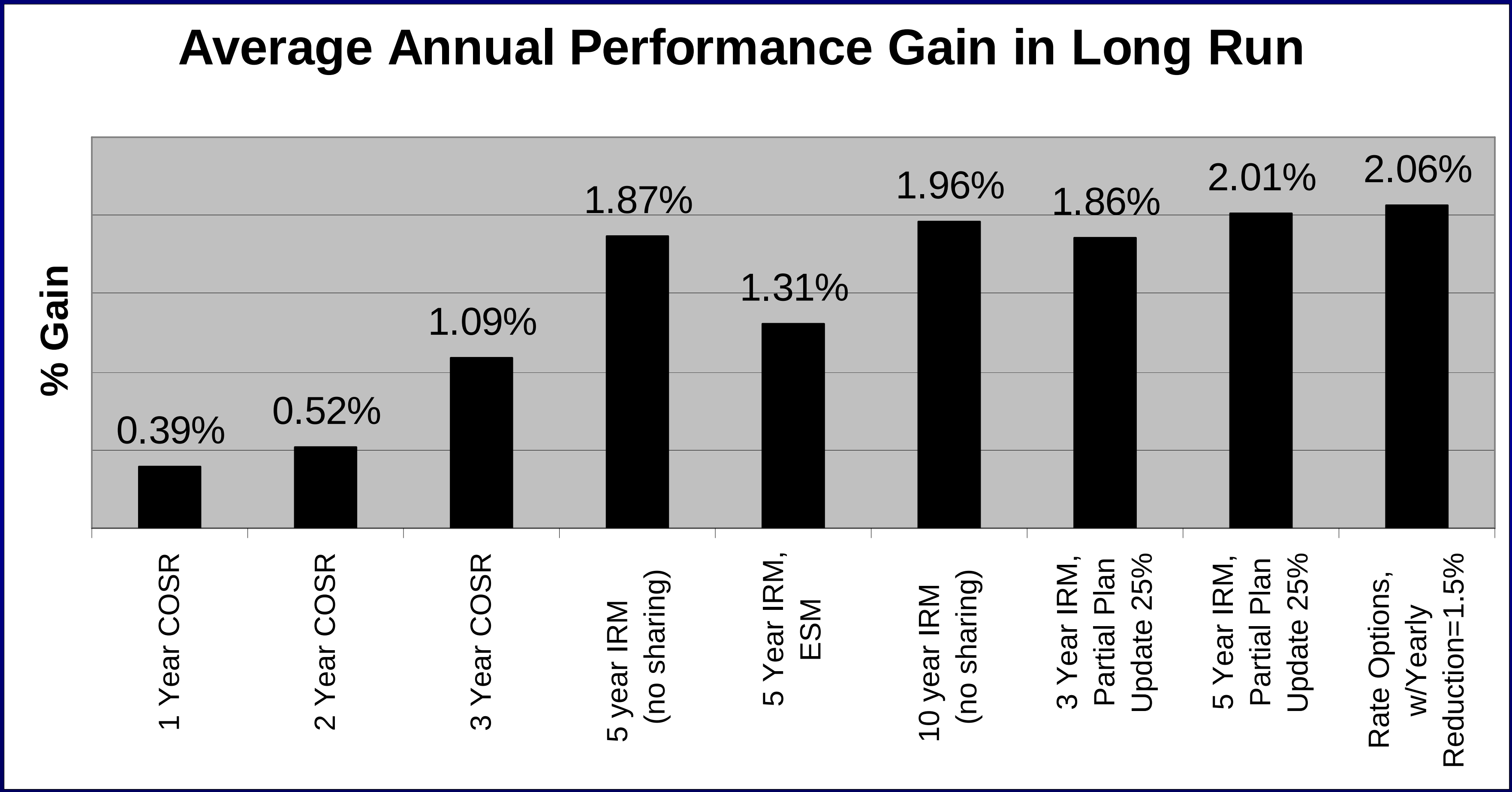
Preliminary Results from Incentive Power Research

20% initial inefficiency	Cost Reduction (NPV)	Relative Incentive Power	Average Annual Performance Gain			
			1st Rate Cycle	2nd rate cycle	3rd rate cycle	Long run
Reference Regulatory Options						
Cost plus	0	**0%**	0.00%	0.00%	0.00%	0.00%
1 Year Cost of Service	647	**29%**	12.16%	-2.84%	1.53%	0.39%
2 Year Cost of Service	816	**37%**	1.99%	0.53%	0.38%	0.52%
3 Year Cost of Service	1107	**50%**	1.14%	0.75%	0.06%	1.09%
Full Rate Externalization	2194	**100%**	3.93%	4.25%	3.78%	2.06%
Impact of Plan Term						
Term = 3 years	1107	**50%**	1.14%	0.75%	0.06%	1.09%
Term = 5 years	1446	**66%**	-0.19%	1.54%	1.75%	1.87%
Term = 10 years	1740	**79%**	1.13%	2.56%	2.43%	1.96%
Impact of Earnings Sharing						
3-year plans, ESM						
No Sharing	1107	**50%**	1.14%	0.75%	0.06%	1.09%
Company Share = 75%	933	**43%**	1.41%	0.43%	0.79%	0.66%
Company Share = 50%	859	**39%**	1.56%	0.39%	0.49%	0.62%
Company Share = 25%	780	**36%**	1.52%	0.53%	0.36%	0.54%
5-year plans, ESM						
No Sharing	1446	**66%**	-0.19%	1.54%	1.75%	1.87%
Company Share = 75%	1333	**61%**	-0.11%	1.31%	1.62%	1.53%
Company Share = 50%	1241	**57%**	0.17%	0.90%	1.32%	1.31%
Company Share = 25%	1134	**52%**	0.80%	0.20%	1.18%	1.20%
10-year plans, ESM						
No Sharing	1740	**79%**	1.13%	2.56%	2.43%	1.96%
Company Share = 75%	1671	**76%**	0.97%	2.28%	2.40%	1.92%
Company Share = 50%	1570	**72%**	0.68%	2.07%	2.08%	1.85%
Company Share = 25%	1507	**69%**	0.58%	1.94%	2.00%	1.75%

Preliminary Results from Incentive Power Research

20% initial inefficiency	Cost Reduction (NPV)	Relative Incentive Power	Average Annual Performance Gain			
			1st Rate Cycle	2nd rate cycle	3rd rate cycle	Long run
Impact of Partial Plan Update						
3-Year Plans, Extern						
Externalized Percentage = 0%	1107	**50%**	1.14%	0.75%	0.06%	1.09%
Externalized Percentage = 10%	1185	**54%**	1.04%	0.93%	-0.05%	1.20%
Externalized Percentage = 25%	1562	**71%**	0.32%	-0.64%	1.80%	1.86%
Externalized Percentage = 50%	1873	**85%**	-1.98%	2.70%	2.93%	1.98%
5-Year Plans, Extern						
Externalized Percentage = 0%	1469	**67%**	-0.19%	1.54%	1.75%	1.87%
Externalized Percentage = 10%	1525	**70%**	-0.07%	1.72%	1.87%	1.94%
Externalized Percentage = 25%	1640	**75%**	0.17%	2.20%	2.40%	2.01%
Externalized Percentage = 50%	1895	**86%**	1.64%	2.95%	2.89%	2.04%
Impact of Rate Options						
Yearly rate reduction = 1%	2193	**100%**	3.92%	4.25%	3.78%	2.06%
Yearly rate reduction = 1.25%	2193	**100%**	3.92%	4.25%	3.78%	2.06%
Yearly rate reduction = 1.5%	2194	**100%**	3.92%	4.25%	3.78%	2.06%

Preliminary Incentive Power Results



Pacific Economics Group
Economic and Litigation Consulting

Efficiency Carryover Pro:

Better long-term performance

Less gaming of opex, capex

More assurance of customer benefits

Efficiency Carryover Con:

Regulatory risk may increase considerably

Rebasing Rules (cont'd)

Preliminary Assessment

Plans should include efficiency carryover mechanisms

Rate option approach contains risk – a material advantage

Staff welcomes alternative ideas

Rebasing Rules (cont'd)

Partial Plan Update (PPU) Example

In rebasing year,

growth PCI^{IRM1} = 1%
growth $Rates^{COSR}$ = -1 %
growth $Rates^{PPU}$ = .75 x -1% + .25 x 1%
= -.75 % + .25%
= -.5

Firm keeps .5% for at least five years

Pacific Economics Group
Economic and Litigation Consulting

Rebasing Rules (cont'd)

Rate Option Example

Rate adjustments in plan out years the same for all utilities

growth PCI = growth GDPPI - 1

In rebasing year,

$$P^{COSR} = P_0 \text{ x } (\text{growth GDPPI} - 1)^4 \text{ x growth Rates}^{COSR}$$

$$P^{\text{Rate Option}} = P_0 \text{ x } (\text{growth GDPPI} - 1.25)^5$$

Price Cap Index Design Introduction

In a typical price cap index, PCI growth determined by formula

$$\text{growth } PCI = \text{growth } P - X + Z$$

P = Price inflation index
X = X factor
Z = Z factor adjusts PCI growth for miscellaneous developments

2 established approaches to PCI design

1. North American Approach
2. British Approach

North American PCI Design

In North America, index design commonly based on index research

Logic of Economic Indexes

If an industry earns competitive return,

$$\text{trend Prices}^{\text{Industry}} = \text{trend Unit Cost}^{\text{Industry}}$$

>>> PCI "calibrated" to track "industry" unit cost trend

$$\text{trend Unit Cost} = \text{trend Input Prices} - \text{trend TFP}$$

TFP = Total Factor Productivity

North American PCI Design

Logic of Economic Indexes (cont'd)

Key issues in North American price cap proceedings:

How can PCI formula yield right adjustments for

- Input prices
- Productivity

TFP

TFP Basics

trend Productivity = trend Output Quantities
- trend in Input Quantities

Trend Input Quantities
= weighted average of trends in input quantity *subindexes*
(*e.g.* employees, capital, miscellaneous)

Weights: *cost* shares

Trend Output Quantities
= weighted average of trends in output quantity *subindexes*
(*e.g.* customers, delivery volume)

Weights: *cost elasticity* shares (or) *revenue* shares

TFP Basics (cont'd)

Index design determines scope of performance that is measured

Input Scope

Labor Productivity	*1* input
Multi-Factor Productivity	*Multiple* inputs
Total Factor productivity	*All* inputs

Output Index Scope

Revenue Shares	*Cost & marketing* performance
Cost Elasticity Shares	Only *cost* performance

TFP (cont'd)

Data Requirements

Output quantities (*e.g.* customers, delivery volume)

Input quantities

Labour:	FTE employees
Materials & Services:	growth Cost – growth Input Prices
Capital:	growth Plant Additions – growth Construction Cost Index

TFP (cont'd)

Sampling Issues

Alternative samples available for index calculation

- Ontario utilities
- Canadian utilities (*e.g.* Stats Canada)
- U.S. utilities (*e.g.* PEG sample)
- Multiple sources

Example: Use data on U.S. productivity trends to determine productivity adjustment for firms with aggressive cast iron replacement programs

Sources of Productivity Growth

trend in TFP = trend Input Prices – trend Unit Cost

Theoretical & empirical work has identified sources of TFP growth

Short Run Effects

- Capacity utilization
- Volume/customer
- Reduced “X-Inefficiency”

Long Run Effects

- Technological change
- Scale Economies
- Scope Economies

TFP Measurement Controversies

Gray areas in science

- invite controversy
- encourage gaming, dueling expert witnesses

e.g. 1: Output Growth

What Variables?	Customers Volumes Peak Demand
What Weights?	Revenue Shares Cost Elasticities

e.g. 1: Output Growth Controversy (cont'd)

Appropriate output index depends on research application

Revenue Cap Index (*e.g.* Enbridge TPBR)

- Output quantity index has *cost elasticity* weights
- TFP index should consider only *cost* efficiency

Price Cap Index (*e.g.* Union Gas)

- Output quantity index has *revenue share* weights
- TFP index should considers *cost* and *marketing* efficiency

Divisia Logic

If …

trend Revenue = trend Output Prices + trend Output Quantities

trend Cost = trend Input Prices + trend Input Quantities

trend Revenue = trend Cost

then …

trend Output Prices

= trend Input Prices
- (trend Output Quantities – trend Output Quantities)

= trend Input Prices – trend TFP

e.g. 1: Output Growth Controversy (cont'd)

Output index weighting influences volume/customer impact

Rate designs inconsistent with cost impact of billing determinants

- *Customers* chief *cost* driver
- *Volumes* & max demand chief *revenue* drivers

Volume/customer trend affects utility finances

Power Distribution	*Rising* volume/customer *bolsters* profits
Gas Distribution	*Declining* volume/customer *drains* profits

>>> Right output index key to just & reasonable PBR

Trends in Average Gas Use for Residential & Commerical Gas Customers by State[1]

	region	1997-2005 Non-Normalized	1997-2005 Normalized[2]	1997-2002 Non-Normalized	1997-2002 Normalized[2]	2002-2005 Non-Normalized	2002-2005 Normalized[2]
National Aggregate		**-1.77%**	**-1.58%**	**-1.90%**	**-1.50%**	**-1.55%**	**-1.74%**
North East Aggregate		**-0.99%**	**-1.01%**	**-1.37%**	**-0.43%**	**-0.37%**	**-2.00%**
Connecticut	NE	-1.53%	-1.33%	-1.68%	-0.35%	-1.26%	-2.97%
D.C.	NE	-0.59%	-0.98%	-1.95%	-1.32%	1.68%	-0.42%
Maine	NE	3.20%	3.70%	7.32%	8.31%	-3.67%	-3.98%
Maryland	NE	0.93%	0.53%	0.67%	1.30%	1.35%	-0.75%
Massachusetts[3]	NE	-4.82%	-4.94%	-6.04%	-5.10%	-1.79%	-4.55%
New Hampshire	NE	0.64%	1.02%	-0.81%	0.37%	3.05%	2.09%
New Jersey	NE	-1.82%	-1.79%	-3.40%	-2.46%	0.81%	-0.68%
New York	NE	-0.69%	-0.75%	-0.05%	0.87%	-1.77%	-3.44%
Pennsylvania	NE	-1.32%	-1.25%	-2.47%	-1.48%	0.59%	-0.87%
Rhode Island	NE	-0.86%	-0.93%	-1.69%	-0.45%	0.53%	-1.73%
Vermont	NE	-3.05%	-2.51%	-4.88%	-3.76%	0.00%	-0.42%
Southeast Aggregate		**-0.55%**	**-0.87%**	**-1.00%**	**-0.96%**	**0.19%**	**-0.74%**
Delaware	SE	-0.46%	-0.81%	-1.14%	-0.16%	0.66%	-1.90%
Florida	SE	2.45%	0.85%	4.59%	2.76%	-1.12%	-2.33%
Georgia	SE	-1.00%	-1.46%	-1.68%	-2.12%	0.14%	-0.38%
North Carolina	SE	-0.66%	-0.52%	-1.98%	-1.09%	1.53%	0.44%
South Carolina	SE	-0.84%	-0.90%	-1.24%	-0.72%	-0.17%	-1.20%
Virginia[3]	SE	-2.06%	-1.52%	-3.28%	-2.26%	0.97%	0.34%
West Virginia	SE	-1.41%	-1.03%	-2.14%	-0.94%	-0.19%	-1.18%
North Central Aggregate		**-2.23%**	**-1.72%**	**-2.44%**	**-1.59%**	**-1.88%**	**-1.94%**
Illinois	NC	-1.93%	-1.24%	-1.98%	-1.06%	-1.84%	-1.54%
Indiana	NC	-1.76%	-1.13%	-2.78%	-1.55%	-0.06%	-0.44%
Iowa	NC	-3.09%	-2.44%	-3.34%	-2.47%	-2.67%	-2.40%
Kansas	NC	-2.68%	-2.17%	-0.96%	-0.61%	-5.55%	-4.75%
Michigan	NC	-2.28%	-1.95%	-2.70%	-1.89%	-1.60%	-2.04%
Minnesota	NC	-2.07%	-1.44%	-0.85%	-0.36%	-4.11%	-3.24%
Missouri	NC	-2.62%	-1.78%	-2.98%	-2.21%	-2.02%	-1.06%
Nebraska	NC	-4.02%	-3.39%	-4.16%	-3.84%	-3.79%	-2.64%
North Dakota	NC	-2.84%	-2.31%	-1.07%	-0.91%	-5.79%	-4.63%
Ohio	NC	-2.06%	-1.86%	-3.16%	-2.05%	-0.23%	-1.55%
South Dakota	NC	-2.54%	-1.77%	-2.87%	-2.34%	-2.00%	-0.83%
Wisconsin	NC	-2.60%	-2.15%	-2.31%	-1.58%	-3.08%	-3.10%

Trends in Average Gas Use for Residential & Commerical Gas Customers by State[1]

South Central Aggregate		**-1.94%**	**-1.28%**	**-1.86%**	**-1.37%**	**-2.08%**	**-1.14%**
Alabama	SC	-2.28%	-1.71%	-2.95%	-2.26%	-1.16%	-0.79%
Arkansas	SC	-1.48%	-0.82%	-0.32%	-0.39%	-3.40%	-1.53%
Kentucky	SC	-2.47%	-1.91%	-3.10%	-1.97%	-1.43%	-1.80%
Louisiana	SC	-1.70%	-0.57%	-0.94%	-0.56%	-2.97%	-0.57%
Mississippi[3]	SC	-1.86%	-1.20%	-1.44%	-1.01%	-2.91%	-1.68%
Oklahoma	SC	-1.93%	-1.32%	-1.54%	-1.74%	-2.59%	-0.62%
Tennessee	SC	-2.14%	-1.58%	-2.33%	-1.46%	-1.83%	-1.77%
Texas[3]	SC	-3.33%	-1.78%	-1.92%	-1.03%	-6.84%	-3.67%
Northwest Aggregate		**-2.19%**	**-2.15%**	**-1.53%**	**-1.93%**	**-3.29%**	**-2.53%**
Idaho	NW	-1.60%	-1.78%	-0.26%	-0.66%	-3.84%	-3.64%
Montana	NW	-2.48%	-2.41%	-0.97%	-1.48%	-4.99%	-3.95%
Oregon	NW	-1.73%	-1.86%	-1.26%	-1.54%	-2.51%	-2.40%
Washington	NW	-2.23%	-2.11%	-1.95%	-2.42%	-2.70%	-1.60%
Wyoming	NW	-2.86%	-2.48%	-1.64%	-1.91%	-4.90%	-3.42%
Southwest Aggregate		**-1.65%**	**-1.92%**	**-1.41%**	**-2.61%**	**-2.04%**	**-0.76%**
Arizona	SW	-2.92%	-2.05%	-2.89%	-2.28%	-2.99%	-1.66%
California	SW	-1.11%	-1.87%	-0.94%	-2.98%	-1.39%	-0.02%
Colorado	SW	-3.07%	-2.30%	-2.23%	-1.79%	-4.48%	-3.16%
Nevada	SW	-2.19%	-1.60%	-3.13%	-2.25%	-0.63%	-0.50%
New Mexico	SW	-3.35%	-2.72%	-3.33%	-2.89%	-3.39%	-2.42%
Utah	SW	-2.59%	-2.63%	-2.24%	-3.13%	-3.19%	-1.80%

1 Source of volume data: Energy Information Administration Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"

2 Data are normalized using the estimated regression equation grcvn = -0.011+0.607*ghdd where grcvn is the annual change in residential and commercial gas volumes by state and ghdd is the annual change in heating degree days by state. The t-statistics on the regression coefficients are -4.718 and 22.981, respectively. Heating degree days data for this equation is from NOAA (National Oceanic and Atmospheric Administration) Historical Climatology Series 5-1.

3 Data is missing for 2005; period ends in 2004

*** Residental Volume and Customer Data in addition to Commercial Customer data was entered from 2003-05, while Commercial Volume was entedred from 2000-05**

e.g. 1: Output Growth Controversy (cont'd)

>>> Right output index key to just & reasonable IR

>>> Productivity trend likely lower for *gas* distribution than for *power* distribution PCI

>>> Productivity trend likely lower for gas *price* cap index than for gas *revenue* cap index

Impact of Volume/Customer & Cast Iron Replacement on Productivity Trends of 39 U.S. Gas LDCs,1994-2004

	Input Quantities		Output Quantities		Output Quantity Index Weights: 80% Customers/20% Deliveries					Output Quantity Index Weights: 20% Customers/ 80% Deliveries				
	All	O&M	80/20	20/80	TFP	PFP-Labour	PFP-M&S	PFP-Capital	PFP-OM	TFP	PFP-Labour	PFP-M&S	PFP-Capital	PFP-OM
All	0.76%	-0.76%	1.53%	0.44%	0.77%	5.90%	-1.43%	-0.10%	2.31%	-0.33%	4.80%	-2.52%	-1.20%	1.22%
Significant Cast Iron Reduction (3%)	0.57%	-1.44%	0.93%	-0.26%	0.36%	5.89%	-1.14%	-0.90%	2.41%	-0.82%	4.71%	-2.32%	-2.09%	1.23%
Some Reduction (0-3%)	1.04%	-0.21%	1.77%	0.64%	0.73%	4.89%	-2.18%	0.12%	1.98%	-0.40%	3.76%	-3.31%	-1.01%	0.85%
No reduction	0.72%	-0.39%	2.19%	1.29%	1.47%	7.21%	-0.92%	0.89%	2.58%	0.57%	6.31%	-1.82%	-0.01%	1.68%
Some + None (<3%)	0.90%	-0.29%	1.95%	0.92%	1.05%	5.90%	-1.63%	0.45%	2.24%	0.02%	4.87%	-2.66%	-0.58%	1.21%
Significant - All (Nominal)	-0.20%	-0.68%	-0.60%	-0.69%	-0.41%	0.00%	0.29%	-0.80%	0.10%	-0.50%	-0.10%	0.20%	-0.89%	0.01%
Significant - All (w/slow-growth adjustment)					-0.33%	0.08%	0.37%	-0.72%	0.18%	-0.40%	0.00%	0.29%	-0.80%	0.10%

TFP Measurement Controversies (cont'd)

e.g. 2 Capital Cost & Quantity

TFP research requires each cost to decompose into prices, quantities

Capital Cost = Capital Price x Capital Quantity

Alternative approaches to capital cost measurement available

Measurement Issues:

- Book or replacement valuation of plant?
- Straight-line depreciation or geometric decay?

e.g. 2 Capital Cost & Quantity (cont'd)

Here is quantity index for *geometric decay*

$$Quantity^{Total}_{t} = (1\text{-}d) \times Quantity^{Total}_{t-1} + Quantity^{Added}_{t}$$

where

$$Quantity^{Added}_{t} = Capex_{t} / WKA_{t}$$

$$WKA_{t} = \text{Construction Cost Index}$$

Commonly used in TFP research

TFP Precedents

Federal governments of U.S. & Canada report TFP trends

Source	*Activity*	*Estimated Trend*
BLS	U.S. economy	1.3%
Stats Canada	Canadian economy	1.1%
Stats Canada	Electric GT&D	- 1.6%
Stats Canada	Gas & water distribution	0.4%

Regulators in several jurisdictions have weighed evidence on utility industry TFP trends, made judgments

Table 1
X FACTORS APPROVED IN INDEXING PLANS FOR GAS AND ELECTRIC UTILITIES

Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure (P)	Stretch Factor	X-Factor	Comments
Bundled power service	Pacificorp	1994-1996	California	1.4%	Industry specific	NA	1.4%	Company specific productivity
Bundled power service	Central Maine Power (I)	1995-1999	Maine	NA	GDPPI	NA	0.9% (average)	
Gas distribution	Southern California Gas	1997-2002	California	0.50%	Industry specific	0.80% (Average)	2.30% (Average)	Special 1% factor added to X to reflect declining rate base
Power distribution	Southern California Edison	1997-2002	California	NA	CPI	0.58% (Average)	1.48% (Average)	0.90% productivity trend estimated by Edison and Commission staff but not formally acknowledged by CPUC
Gas distribution	Boston Gas (I)	1997-2003	Massachusetts	0.40%	GDPPI	0.50%	0.50%	
Gas distribution	San Diego Gas and Electric	1999-2002	California	0.68%	Industry specific	0.55% (Average)	1.23% (Average)	
Power distribution	San Diego Gas and Electric	1999-2002	California	0.92%	Industry specific	0.55% (Average)	1.47% (Average)	
Gas distribution	Consumers Gas	2000-2002	Ontario	0.63%	CPI	0.50%	1.10%	O&M Productivity
Power distribution	All Ontario distributors	2000-2003	Ontario	0.86%	Industry specific	0.25%	1.5%	Productivity trend referenced is the 10 year average growth rate X factor is based on 5 and 10 year weighted average
Gas distribution	Union Gas	2001-2003	Ontario	0.9%	GDPPI	0.5%	2.5%	
Power distribution	Central Maine Power (II)	2001-2007	Maine	NA	GDPPI	NA	2.57% (Average)	
Gas distribution	Berkshire Gas	2002-2011	Massachusetts	0.40%	GDPPI	1.0%	1.0%	Adopted the productivity study used by Boston Gas I
Gas distribution	Boston Gas (II)	2004- 2013	Massachusetts	0.58%	GDPPI	0.30%	0.41%	
Power distribution	All Dutch distributors	2004-2006	Netherlands	1.5%	CPI	NA	NA	X factor assigned by regulator is not determined on comparable basis to the rest in the sample
Power distribution	All New Zealand distributors	2004-2009	New Zealand	2.1%	CPI	0% (Average)	1%	
Gas distribution	Bay State Gas	2006-2015	Massachusetts	0.58%	GDPPI	0.4%	0.51%	Adopted the productivity study used by Boston Gas II
Power distribution	Nstar	2006-2012	Massachusetts	NA	GDPPI	NA	0.63% (Average)	

Table 1 (cont) X FACTORS APPROVED IN INDEXING PLANS FOR GAS AND ELECTRIC UTILITIES								
Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure (P)	Stretch Factor	X-Factor	Comments
All utilities	Sample Average			0.88%		0.49%	1.28%	
All, industry specific P	Sample Average						1.58%	
All, macroeconomic P	Sample Average						1.27%	
Power distribution	Sample Average			1.35%			1.44%	
Power distribution, industry specific P	Sample Average						1.49%	
Power distribution, macroeconomic P	Sample Average						1.42%	
Gas distribution	Sample Average			0.58%			1.19%	
Gas distribution, industry specific P	Sample Average						1.77%	
Gas distribution, macroeconomic P	Sample Average						1.00%	

North American PCI Design (*cont'd*)

Inflation Measures

Two kinds of inflation measures widely used in PBR

1. Macroeconomic (e.g. CPI, GDP-IPI)

2. Industry-Specific

Industry-Specific Inflation Measures

Basic Idea

Index growth is weighted average of growth in *sub*indexes

Weights = industry cost shares

Precedents

U.S. Railroads

California	Pacificorp	
	Sempra	San Diego Gas & Electric
		Southern California Gas
Ontario	Power Distribution IRM1	

Pacific Economics Group
Economic and Litigation Consulting

Case Study: Ontario Power Dx

Input Category	Approved Subindex
Labor	$$/Employee, Ontario distributors
Other O&M	Industrial Producer Price Index
Capital	Custom Index based on …
	Canadian construction cost index Bank of Canada long bond yields

Controversy encountered in capital subindex specification

Industry-Specific Inflation Measures (cont'd)

Capital Price Indexes

Capital price index depends on capital cost assumptions

Four capital cost components are potentially relevant

- Opportunity Cost
- Depreciation
- Taxes
- Capital Gains

Capital Price Indexes

Here is the formula for replacement valuation & geometric decay

$$Price^{Capital} = d * WKA_{t-1} + r_t * WKA_{t-1} - (WKA_t - WKA_{t-1})$$

WKA_t = construction cost index
r_t = cost of funds
d = (constant) depreciation rate

Capital cost drivers include
- Construction Cost
- Cost of funds

Inherently volatile, need smoothing

Capital Price Indexes (cont'd)

Here is a formula for *book* valuation, geometric decay

$$Price^{Capital} = (d + r_t) \times SUM_s\ weight_{t-s}\ WKA_{t-s}$$

WKA_t = construction cost index
r_t = cost of funds
d = (constant) depreciation rate

Capital cost drivers include Construction Cost
Cost of funds

No smoothing needed

PEG Pacific Economics Group
Economic and Litigation Consulting

Preliminary IPI for Gas Distribution

Calculation of Smoothed Gas Distribution Industry IPI

	Capital (smoothed)				Labour				Materials and Services				Smoothed IPI - Natural Gas Industry	
Year	Index[1]	1996 Normalization	Growth	Weight[o]	Index[2]	1996 Normalization	Growth	Weight[o]	Index[3]	1996 Normalization	Growth	Weight[o]	Level	Growth
1996	13.7	1.0000		59.0%	649.6	1.000		20.0%	99.3	1.00		21.0%	1.00	
1997	15.7	1.1431	13.4%	59.0%	663.7	1.022	2.2%	20.0%	100.0	1.01	0.7%	21.0%	1.09	8.5%
1998	15.2	1.1123	-2.7%	59.0%	672.7	1.036	1.3%	20.0%	100.4	1.01	0.4%	21.0%	1.07	-1.3%
1999	15.1	1.1012	-1.0%	59.0%	683.7	1.053	1.6%	20.0%	102.2	1.03	1.8%	21.0%	1.08	0.1%
2000	19.1	1.3923	23.5%	59.0%	700.1	1.078	2.4%	20.0%	106.5	1.07	4.2%	21.0%	1.25	15.2%
2001	19.5	1.4201	2.0%	59.0%	712.9	1.097	1.8%	20.0%	107.6	1.08	1.0%	21.0%	1.27	1.7%
2002	18.5	1.3494	-5.1%	59.0%	726.2	1.118	1.9%	20.0%	107.6	1.08	0.1%	21.0%	1.24	-2.6%
2003	21.9	1.6004	17.1%	59.0%	734.8	1.131	1.2%	20.0%	106.2	1.07	-1.4%	21.0%	1.37	10.0%
2004	21.8	1.5884	-0.8%	59.0%	748.1	1.152	1.8%	20.0%	109.5	1.10	3.1%	21.0%	1.38	0.6%
2005	21.5	1.5708	-1.1%	59.0%	768.6	1.183	2.7%	20.0%	111.2	1.12	1.5%	21.0%	1.38	0.2%
Average 1997-2003			**5.6%**				**1.7%**				**1.0%**			**4.5%**
Average 1996-2005			**5.0%**				**1.9%**				**1.3%**			**3.6%**
Average 1996-2000			**8.3%**				**1.9%**				**1.8%**			**2.4%**
Average 2001-2005			**2.0%**				**1.5%**				**0.7%**			**1.6%**

[o]Source: Recent PEG econometric research, as reported in testimony for Sempra Energy.

[1]Source: PEG Calculation based upon Stats Canada Utility Construction Cost Index and Canadian Government Bond Yield (Greater than 10 Years), and ROE for a sample of 14 companies listed on the TSX 60 Index. The capital gains term was smoothed.

[2]Source: Average Weekly Earnings, Total Economy of Ontario: Stats Canada; http://statcan.ca

[3]Source: Industrial Product Price Index, All Manufacturing: Stats Canada; http://statcan.ca

Macroeconomic Inflation Measures

When PCI has *macroeconomic* inflation measure, X factor calibration involves two terms:

Productivity Differential ($TFP^{industry}$ - $TFP^{economy}$)

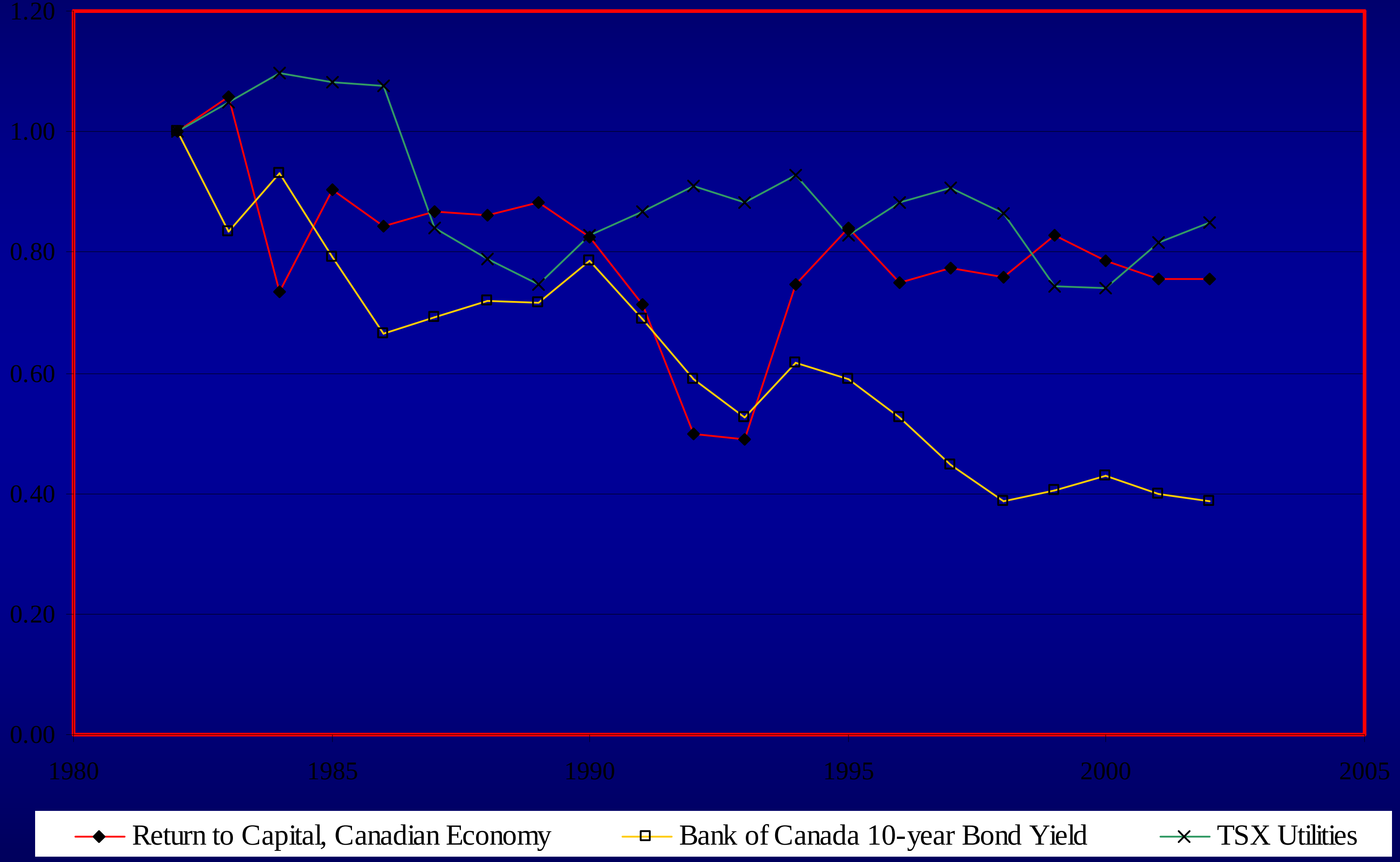
Input Price Differential ($Prices^{economy}$ - $Prices^{industry}$)

Input price differential controversial in some proceedings

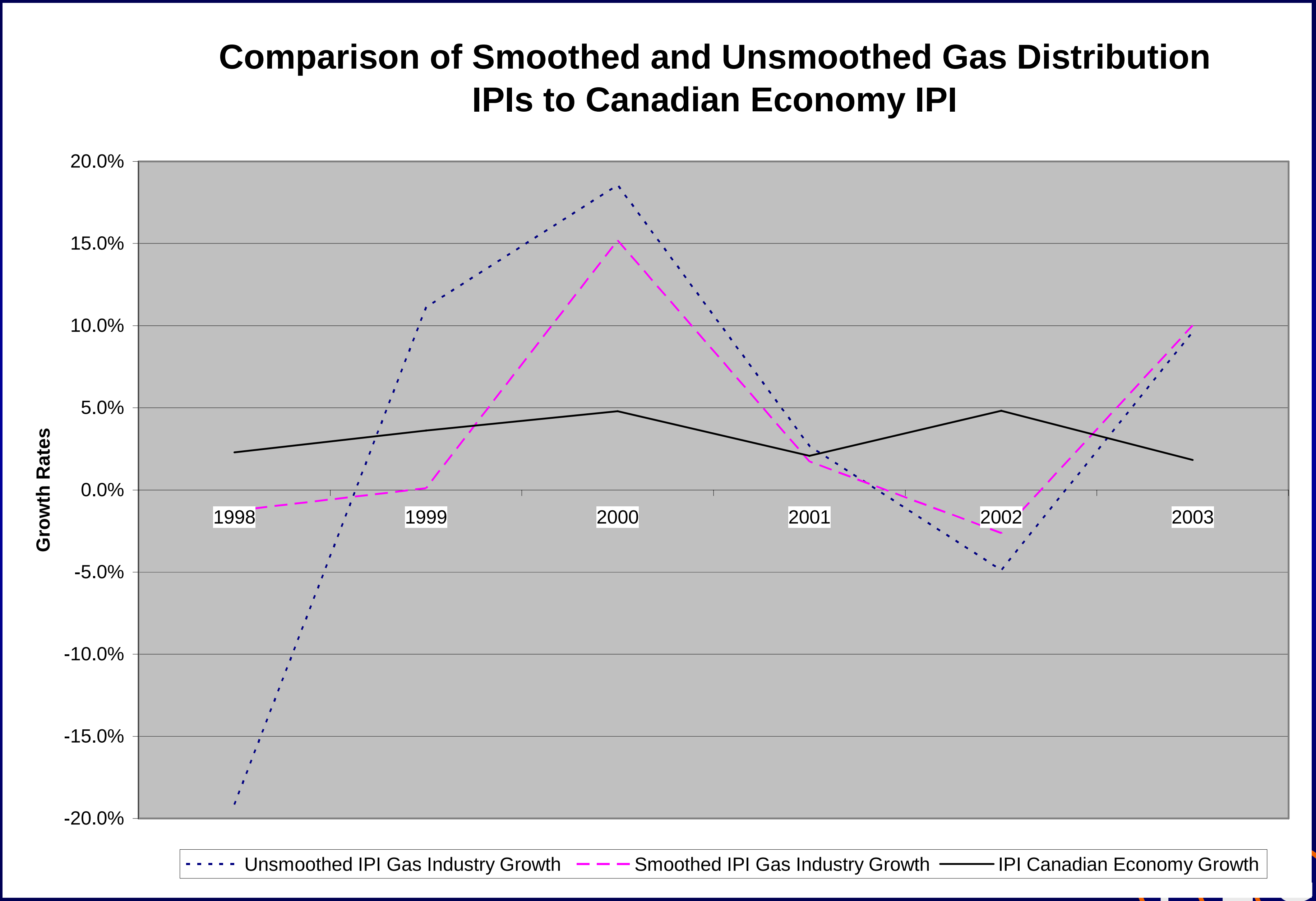
Central Maine Power	Power Dx	ME
Union Gas	Gas Dx	ON

Reasons:
- Capital intensive industry
- Capital price volatility
- Falling trend in long bond yields

Alternative Return to Capital Measures, Growth Trends 1982-2002



Pacific Economics Group
Economic and Litigation Consulting


Comparison of Smoothed and Unsmoothed Gas Distribution
IPIs to Canadian Economy IPI
Growth Rates
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
-20.0%
1998
1999
2000
2001
2002
2003
Unsmoothed IPI Gas Industry Growth
Smoothed IPI Gas Industry Growth
IPI Canadian Economy Growth

Comparison of Gas Distribution IPI to that of Canadian Economy, 1997-2005

Year	IPI Canadian Economy Growth	Unsmoothed IPI Gas Industry Growth	Smoothed IPI Gas Industry Growth	Difference Unsmoothed	Difference Smoothed
1997	2.8%	-3.0%	8.5%	-5.9%	5.6%
1998	2.3%	-19.2%	-1.3%	-21.4%	-3.6%
1999	3.6%	11.1%	0.1%	7.5%	-3.5%
2000	4.8%	18.6%	15.2%	13.8%	10.4%
2001	2.1%	2.7%	1.7%	0.6%	-0.3%
2002	4.8%	-4.9%	-2.6%	-9.7%	-7.4%
2003	1.8%	9.6%	10.0%	7.8%	8.2%
2004		-0.9%	0.6%		
2005		-3.5%	0.2%		
Formula	**[A]**	**[B]**	**[C]**	**[A] - [B]**	**[A] - [C]**
Average 1997-2003	**3.2%**	**2.1%**	**4.5%**	**1.1%**	**-1.3%**

Inflation Measure

Conclusions

Choice is “between a rock and a hard place”

Macroeconomic: Controversy over input price differential

Industry Specific: Controversy over index design

MNL personal preference: IPI w COSR capital cost

Stretch Factors

Stretch factors often added to X factors

Higher X >>>> More guaranteed customer benefits

Impact on performance incentives controversial

- High stretch doesn’t strengthen performance incentives
- But stretch generates stronger incentives than ESM

Precedents:

- 0.50% “consumer productivity dividend” for AT&T
- 0.49% average, energy utilities

Stretch Factors (cont'd)

Incentive Power Results

Incentive power research sheds light on stretch factor issue

Plan Term	TFP Growth
1 year	0.39%
2 years	0.52%
3 years	1.09%
5 years	1.87%
10 years	1.96%
Permanent rate externalization	2.06%

Stretch factor can share expected gains

X Factor Precedents

X factors depend on chosen inflation measure

Inflation Measure	X Factor Terms
Industry Specific	Productivity Trend Stretch Factor
Macroeconomic	Productivity *Differential* Input Price *Differential* Stretch Factor

X Factor Precedents (cont'd)

Table 1 (cont) X FACTORS APPROVED IN INDEXING PLANS FOR GAS AND ELECTRIC UTILITIES								
Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure (P)	Stretch Factor	X-Factor	Comments
All utilities	Sample Average			0.88%		0.49%	1.28%	
All, industry specific P	Sample Average						1.58%	
All, macroeconomic P	Sample Average						1.27%	
Power distribution	Sample Average			1.35%			1.44%	
Power distribution, industry specific P	Sample Average						1.49%	
Power distribution, macroeconomic P	Sample Average						1.42%	
Gas distribution	Sample Average			0.58%			1.19%	
Gas distribution, industry specific P	Sample Average						1.77%	
Gas distribution, macroeconomic P	Sample Average						1.00%	

X Factor Precedents (cont'd)

Data on utility rate trends contain *implicit* X factors

IMPLICIT X FACTOR IN GAS DISTRIBUTION RATES, 1991-2005

Year	PPI Natural Gas Distribution - Transportation Only[1]			GDP-PI[2]			Implied X Factor[3]
	Level	Level (1991=100)	Growth Rate	Level	Level (1991=100)	Growth Rate	
1991	96.8	100.0		84.5	100.0		
1992	99.5	102.8	2.8%	86.4	102.3	2.3%	-0.5%
1993	101.5	104.9	2.0%	88.4	104.7	2.3%	0.3%
1994	101.2	104.5	-0.3%	90.3	106.9	2.1%	2.4%
1995	106.9	110.4	5.5%	92.1	109.1	2.0%	-3.5%
1996	105.7	109.2	-1.1%	93.9	111.1	1.9%	3.0%
1997	109.4	113.0	3.4%	95.4	113.0	1.6%	-1.8%
1998	103.6	107.0	-5.4%	96.5	114.2	1.1%	6.6%
1999	102.3	105.7	-1.3%	97.9	115.9	1.4%	2.7%
2000	103.9	107.3	1.6%	100.0	118.4	2.2%	0.6%
2001	103.4	106.8	-0.5%	102.4	121.3	2.4%	2.9%
2002	105.5	109.0	2.0%	104.2	123.4	1.7%	-0.3%
2003	108.2	111.8	2.5%	106.3	125.9	2.0%	-0.5%
2004	113.3	117.0	4.6%	109.1	129.2	2.6%	-2.0%
2005	116.1	119.9	2.4%	112.2	132.8	2.8%	0.3%
Formula			**[B]**			**[A]**	**[A] - [B]**
Average 91-05			**1.3%**			**2.0%**	**0.7%**
Average 91-00			**0.8%**			**1.9%**	**1.1%**
Average 00-05			**2.2%**			**2.3%**	**0.1%**

[1]Source: PPI Natural Gas Distribution - Transportation Only: Bureau of Labor Statistics; http://www.bls.gov

[2]Source: GDP-PI: Bureau of Economic Analysis; http://www.bea.gov

[3]Note: Assumes GDPPI - X Index Formula

Accommodations for Major Plant Additions

Some utilities encounter occasional need for major plant additions

Phenomenon most prevalent in power generation & transmission

Least prevalent in energy distribution

Several ways to regulate

- North American Style Indexing
- British Style Indexing
- Hybrid Approaches
- Capex “trackers”

North American Style Indexing

No special accommodation for capex

PCI …

- *Under*compensates for capex in some years
- *Over*compensates in other years
- Utilities left whole on balance

Precedents: Most IR plans based on index research *don't* have special capex provisions

Possible innovations: Adjust PCI to reflect "typical" unit cost impact of comparable U.S. cast iron replacement

British Approach to Rate Index Design

Common approach to rate index design in Britain

1. Determine allowed capex & opex for next five years
2. Recovery of older capital cost assured

>>> Multi-year revenue requirement

3. Forecast other key variables (*e.g.* CPI, output growth)
4. Choose X & initial rates so that…

expected revenues = expected cost

British Approach to Rate Index Design (cont'd)

Emphasis on forecasts has encouraged…

- forecast exaggeration
- regulatory innovation

e.g.

Commission retains independent engineering consultant

Utility rewarded if capex forecast similar

Incents forecast accuracy

Pacific Economics Group
Economic and Litigation Consulting

Accommodations for Major Plant Additions (cont'd)

Hybrid Approaches

Hybrid approaches borrow from COSR and British, North American IR traditions

Victoria, Australia

O&M expenses	North American approach
Capital costs	British approach

Hybrid Approaches (cont'd)

<u>California "Attrition" (*e.g.* Southern California Edison)</u>

O&M expenses	North American approach
	[In practice, growth COM = growth CPI]
Capital costs	Capex fixed for three years in rate case
	COSR for cost of *older* plant

PEG
Pacific Economics Group
Economic and Litigation Consulting

Hybrid Approaches (cont'd)

Western Canada

O&M Expenses & Small Plant Additions	North American approach
Major Plant Additions	CPCN

British Columbia experimenting with incentive-based CPCNs

e.g. Competitive bidding
Construction cost caps

Accommodations for Major Plant Additions (*cont'd*)

Hybrid Approaches (cont'd)

Capex "Tracker" (*e.g.* NSTAR Gas & Electric)

Most costs	North American style indexing
Special capital costs	COSR via Y factor