Enbridge #45

INTERROGATORY

Ref: Stretch Factor

Issue Number:
Issue:

PEG states on page 61 that,

> "A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative stylized regulatory systems."

Please provide the data, programming code, and spreadsheets of PEG's incentive power model used to justify the stretch factor.

RESPONSE

Our statement concerning the acceleration of performance under the proposed regulatory plan is based on the results of research using our incentive power model. This model has been developed over several years to advise both utilities and regulators. We present here some technical details of the incentive power model. We explain our assumptions, our model of utility behavior, the regulatory plans considered, and our choices of parameters. We also describe the program used to "solve" for the firm's optimum behavior given the regulatory environment it faces. We conclude our response with a discussion of the model's results for the Ontario Energy Board.

The code for the model is contained in an attachment. Please note that for commercial proprietary reasons PEG believes that the code is confidential. The code will be released to parties that have signed the Form of Declaration and Undertaking pursuant to the Board's Practice.

Please also note that the results discussed in testimony were based on older code that has been supplanted on the basis of further research. We elect here to provide the latest version of the work, which yields similar results.

Witness: Mark Lowry

Section 1: Firm Behavior

1.1 Basic Assumptions

The hypothetical firm that is the subject of our research is a utility in the sense that the terms on which it offers service to the public are regulated. To simplify the analysis we assume that there is no demand growth or input price inflation. Input prices and the level of service demanded cannot be influenced by company actions. However, the utility can reduce capital expenditures (capex) and operation and maintenance expenditures (opex) over time through a variety of initiatives.

Utility management chooses levels of effort for each of the available cost reduction initiatives that maximize the present value over a certain planning horizon of the company's profits less its valuation of the distress involved in reducing costs. This decision problem can be stated formally as follows: the firm chooses effort levels for each kind of initiative in each year of the planning horizon that maximize the function

$$NPV_{Total} = NPV_{Profits} - NPV_{distress} = \sum_{t=1}^{\infty} \beta^t \left[profit_t(\boldsymbol{\varepsilon}_\mathbf{t}) - distress_t(\mathbf{m_t}, \mathbf{n_t}) \right]. \qquad (1)$$

Here in each year t, $profit_t$ is the firm's profit and $distress_t$ is the implicit distress cost. The term β, the discount factor, is constant over time. Distress cost in year t is a function of only the efforts exerted on capex and opex reduction in that year, which are measured by vectors $\mathbf{m_t}$ and $\mathbf{n_t}$. Profit in year t is a function of the amount of effort expended on capex and opex reduction initiatives in the current period and all prior periods. We summarize these quantities of efforts by the symbol $\boldsymbol{\varepsilon}_\mathbf{t}$ and assume that there are J kinds of cost reduction projects for both capex and opex.

The level of effort devoted to capex projects of type j undertaken in time t is denoted by $m_{t,j}$. The level of effort devoted to opex projects of type j undertaken is denoted by $n_{t,j}$. The efforts can thus be written in the following $(t+1)\times 2J$ matrix:

$$\boldsymbol{\varepsilon}_{\mathbf{t}} = \begin{bmatrix} m_{t,1} & m_{t,2} & \cdots & m_{t,J} & n_{t,1} & n_{t,2} & \cdots & n_{t,J} \\ m_{t-1,1} & m_{t-1,2} & \cdots & m_{t-1,J-1} & n_{t-1,1} & n_{t-1,2} & \cdots & n_{t-1,J} \\ m_{t-2,1} & m_{t-2,2} & \cdots & m_{t-2,J-1} & n_{t-2,1} & n_{t-2,2} & \cdots & n_{t-2,J} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ m_{0,1} & m_{0,2} & \cdots & m_{0,J} & n_{0,1} & n_{0,2} & \cdots & n_{0,J} \end{bmatrix}$$

In most cases, we restrict the firm's chosen values of the effort variables (the entries of the above matrix) to be non-negative and small enough that they still result in cost reduction instead of cost increase. We relax this assumption during rate case years, allowing firms to intentionally raise costs by a small amount during a rate case year in the hope of increasing the rates they can charge.

1.2 The Profit Function

The firm's profit in each year is $(1-\tau)[revenue_t(\boldsymbol{\varepsilon}_{\mathbf{t}}) - costs_t(\boldsymbol{\varepsilon}_{\mathbf{t}})]$, where τ is the tax rate. The firm cannot directly impact revenue with its behaviour, but can influence it indirectly since cost-reducing projects can affect the cost on which future rates are based.

Each year's cost is the sum of operating expenditures and capital cost. Capital cost has two components: opportunity cost and depreciation. The opportunity cost of capital is $r \cdot capital$, where r is the rate of capital and $capital$ is the value of the utility plant. Depreciation is $d \cdot capital$, where d is the rate of depreciation and is assumed for simplicity to be constant. Putting it all together, we get:

$$profit_t(\boldsymbol{\varepsilon}_{\mathbf{t}}) = (1-\tau)[revenue_t(\boldsymbol{\varepsilon}_{\mathbf{t}}) - opex_t(\boldsymbol{\varepsilon}_{\mathbf{t}}) - (r+d) \cdot capital_t(\boldsymbol{\varepsilon}_{\mathbf{t}})]$$

The value of the capital stock depends on the initial level of capital, subsequent capex, and depreciation. Each year's capital stock is that year's capex added to the previous year's capital stock depleted by a factor of $1-d$. The geometric decay formula used to calculate capital is:

$$\begin{aligned} capital_t &= (1-d)\,capital_{t-1} + capex_t \\ &= (1-d)\left((1-d)capital_{t-2} + capex_{t-1}\right) + capex_t \\ &= (1-d)^2 capital_{t-2} + (1-d)capex_{t-1} + capex_t \\ &= (1-d)^3 capital_{t-3} + (1-d)^2 capex_{t-2} + (1-d)capex_{t-1} + capex_t \\ &\vdots \\ &= (1-d)^t capital_0 + \sum_{i=1}^{t} (1-d)^{t-i} capex_i \end{aligned} \tag{2}$$

Note that the first term is the initial capital stock depreciated t years, and the second term is the sum of all appropriately depreciated capital expenditures made between years 0 and t.

1.3 The Distress Cost Function

In addition to monetary costs, the firm bears implicit costs associated with cost reduction activities. This assumption reflects the stress to the workforce of improving efficiency, particularly when it involves layoffs and more difficult working conditions. We assume that for project j in time period t, these costs are a function of the current year's efforts, where the sensitivity is captured by the coefficients $\sigma_{m,j}$ and $\sigma_{n,j}$:

$$\delta_t(\boldsymbol{\varepsilon}_\mathbf{t}) = \left(\sigma_{m,j} \sum_{j=1}^{J} m_{t,j} + \sigma_{n,j} \sum_{j=1}^{J} n_{t,j}\right)$$

1.4 How Effort Reduces Costs

The manager is able to reduce capex and opex over time. Such cost reduction activities require effort. There are decreasing returns associated with efforts to reduce either capex or opex.

There are two general categories of projects, each having a formula that determines how effort translates into cost reduction. "Permanent projects" reduce costs in the year after their initiation and every subsequent year. "One-offs" reduce costs only in the year they are initiated. In the absence of a cost efficiency frontier, discussed further in Section 1.5, the equation giving the net impact of effort on the year-to-year changes in opex and capex due to a permanent project of type j is:

$$\frac{capex_{t,j} - capex_{t-1,j}}{capex_{t-1,j}} = -\left(\alpha_{m,j} m_{t-1,j} - \alpha_{mm,j} m_{t-1,j}^2\right)$$
$$\frac{opex_{t,j} - opex_{t-1,j}}{opex_{t-1,j}} = -\left(\alpha_{n,j} n_{t-1,j} - \alpha_{nn,j} n_{t-1,j}^2\right).$$

Here $\alpha_{m,j}, \alpha_{mm,j}, \alpha_{n,j}, \text{and } \alpha_{nn,j}$ are coefficients specific to project j. The squared terms here ensure decreasing returns to cost cutting efforts. Notice also that the cost reducing impact of an initiative does not occur until the year after it is undertaken. Rearranging these equations, we get

$$\begin{aligned} capex_{t,j} - capex_{t-1,j} &= -\left(\alpha_{m,j} m_{t-1,j} - \alpha_{mm,j} m_{t-1,j}^2\right) capex_{t-1,j} \\ opex_{t,j} - opex_{t-1,j} &= -\left(\alpha_{n,j} n_{t-1,j} - \alpha_{nn,j} n_{t-1,j}^2\right) opex_{t-1,j} \end{aligned} . \quad (3a)$$

Reducing opex or capex may require implementation costs at the beginning of the project. For a given kind of opex or capex initiative j these costs are given by:

$$\begin{aligned} Up\,front\ capex_{t,j} &= \left(p_{m,j} m_{t,j}\right) capex_{t-1,j} \\ Up\,front\ opex_{t,j} &= \left(p_{n,j} n_{t,j}\right) opex_{t-1,j} \end{aligned} \quad (3b)$$

The parameters of (3a) and (3b) determine the payback period for the initiative. For example, higher values of $p_{m,j}$ and $p_{n,j}$ cause longer payback periods.

We assume that effort put into one-off projects produces results in the same year that are net of any upfront cost. This allows us to use the following equations for time t and a one-off project of type j:

$$\begin{aligned} capex_{t,j} &= -\left(\alpha_{m,j} m_{t,j} - \alpha_{mm,j} m_{t,j}^2\right) capex_{t-1,j} \\ opex_{t,j} &= -\left(\alpha_{n,j} n_{t,j} - \alpha_{nn,j} n_{t,j}^2\right) opex_{t-1}, j \\ Up\,front\ capex_{t,j} &= 0 \\ Up\,front\ opex_{t,j} &= 0 \end{aligned} \quad (4)$$

Using the values for opex and capex from equations (3) and (4) we can compute the full impact of effort on $revenue, opex, capex, \text{and } capital$ for both permanent and one-off projects. The first, $revenue$, is determined by the regulator but influenced by the cost containment effort. The firm knows how the regulator determines their revenue and therefore accounts for the impact of cost reductions on future revenue when deciding upon a level of effort.

The impact on opex and capex are calculated for a permanent project j as follows:

$$\begin{aligned} impact\ on\ capex_{t,j} &= Up\ front\ capex_{t,j} - Total\ capex\ reduction_t \\ &= p_{m,j} m_{t,j} capex_{t-1,j} - \sum_{s=0}^{t-1} \left(\alpha_{m,j} m_{t-s,j} - \alpha_{mm,j} m_{t-s,j}^2 \right) capex_{t-s,j} \qquad (5) \\ impact\ on\ opex_{t,j} &= p_{n,j} m_{t,j} opex_{t-1,j} - \sum_{s=0}^{t-1} \left(\alpha_{n,j} n_{t-s,j} - \alpha_{nn,j} n_{t-s,j}^2 \right) opex_{t-s,j} \end{aligned}$$

For one-off projects, the above equations are simpler because reductions do not pile up over time. They are:

$$\begin{aligned} impact\ on\ capex_{t,j} &= -\left(\alpha_{m,j} m_{t,j} - \alpha_{mm,j} m_{t,j}^2 \right) capex_{t-1,j} \\ impact\ on\ opex_{t,j} &= -\left(\alpha_{n,j} n_{t,j} - \alpha_{nn,j} n_{t,j}^2 \right) opex_{t-1,j} \end{aligned} \qquad (6)$$

Using equations (5) and (6), and assuming that neither capex nor opex change over time for reasons other than the *J* cost-reducing projects, we can compute the firm wide level of $capex$ and $opex$ as follows:

$$\begin{aligned} capex_t &= capex_t^{without\ initiatives} + \sum_{j=1}^{J} impact\ on\ capex_{t,j} \\ &= capex_0 - \sum_{\text{one-off } j} \left(\alpha_{m,j} m_{t,j} - \alpha_{mm,j} m_{t,j}^2 \right) capex_{t-1,j} \\ &\quad + \sum_{\text{permanent } j} \left[p_{m,j} m_{t,j} capex_{t-1,j} - \sum_{s=0}^{t-1} \left(\alpha_{m,j} m_{t-s,j} - \alpha_{mm,j} m_{t-s,j}^2 \right) capex_{t-s,j} \right] \end{aligned}$$

$$\begin{aligned} opex_t &= opex_0 - \sum_{\text{one-off } j} \left(\alpha_{n,j} n_{t,j} - \alpha_{nn,j} n_{t,j}^2 \right) opex_{t-1,j} \\ &\quad + \sum_{\text{permanent } j} \left[p_{n,j} n_{t,j} opex_{t-1,j} - \sum_{s=0}^{t-1} \left(\alpha_{n,j} n_{t-s,j} - \alpha_{nn,j} n_{t-s,j}^2 \right) opex_{t-s,j} \right] \end{aligned}$$

Our approach is very flexible. For both opex and capex reduction activities, we can change the values of parameters $\alpha_{m,j}, \alpha_{mm,j}, \alpha_{n,j}, \alpha_{nn,j}, p_{m,j}$, and $p_{n,j}$. Opex and capex reductions can be modeled separately (by setting some parameters to zero) or considered together. There are a total of 6 parameters that can be varied and that jointly determine the costs and benefits associated with particular cost reduction activities.

Notice also that firms can choose a different level of effort for each project in each year, and that the number of years between when a cost reduction activity is undertaken and the time of the next price review will vary. The amount of time before the next price review can affect the benefits associated with actions taken to reduce costs.

Coefficients on the linear terms play a crucial role in this model, since they affect whether or not any initiatives will be undertaken. For example, for a given regulatory environment, the desirability of undertaking efforts to reduce capex depends on the relationship between $\alpha_{m,j}$ (the reduction coefficient) and $\sigma_{m,j} + p_{m,j}$ (the sum of the distress cost and frontier cost coefficients). If the former is too low relative to the latter parameter, the firm will not find it profitable to engage in capex reductions.

1.5 The Cost Efficiency Frontier

Firms generally have an easier time reducing costs the lower the level of their operating efficiency because there is "low hanging fruit" – projects that reduce costs without much effort. We model these by modifying the cost reduction functions from equation (4) to:

$$\begin{aligned}
\Delta capex_{t,j}(\boldsymbol{\varepsilon}_{\mathbf{t}}) &= -\left(\alpha_{m,j} m_{t-1,j} - \alpha_{mm,j} m^2_{t-1,j}\right) capex_{t-1,j} \\
&\quad + \delta_m m_{t-1,j}\left(capex_{t-1,j} - minimum\ capex_{t,j}\right) \\
\Delta opex_{t,j}(\boldsymbol{\varepsilon}_{\mathbf{t}}) &= -\left(\alpha_{n,j} n_{t-1,j} - \alpha_{nn,j} n^2_{t-1,j}\right) opex_{t-1,j} \\
&\quad + \delta_n n_{t-1,j}\left(opex_{t-1,j} - minimum\ costs_{t,j}\right)
\end{aligned}$$

The second term in each equation makes the reductions bigger when the firm has costs above the minimum level, which is computed beforehand and is the same for all plans. The additional reduction is linear in the firm's distance from the production frontier, scales linearly with effort, and can have varying impact through changes in the parameters δ_m and δ_n.

Section 2: Regulatory Regimes

2.1 Performance Based Regulations

Let us now consider the possible regimes that regulators use to set the prices that dictate firm revenue. Before the firm makes its choices for the amount of cost reduction effort, the regulator announces a regulatory system. Each system that we consider is a combination of rules that address the following issues:

1. How often the regulator undertakes a rate case to reconsider revenue in light of the company's recent cost.
2. How much rates should be adjusted between rate cases to reflect recent earnings.
3. What (and how many) test years should be used to appraise cost during rate cases.
4. How much weight is placed on the firm's own cost, as opposed to some external measure, at the time of the update.

We discuss each of these issues in turn.

<u>Plan Term</u>

Updates come after a pre-specified number of years known to the firm and unchanged during the planning horizon. Since firms typically lose most or all of the benefit from cost reduction initiatives after the next plan update, longer plan terms improve their incentive to undertake those initiatives.

<u>Earnings Sharing</u>

An earnings sharing mechanism (ESM) adjusts rates between update years to reflect firm earnings. ESMs used in modern regulation often include bands that allow a firm to retain a greater share of incremental profit as returns increase (a progressive ESM) or bands that allow a firm to retain a lower share of incremental profits as returns increase (a regressive ESM). In this study we consider only ESMs with the same company/customer split for all earnings variances.

To illustrate, consider a plan with 50% earnings sharing. If the firm makes $10 million in surplus earnings during year t, the regulator passes $5 million along to consumers in the form of a rate reduction in year $t+1$. The firm sees this reduction as a $5 million loss in revenue and consumers see it as a $5 million benefit.

<u>Test Year</u>

In North America, regulators commonly choose between a historical and a forward test year approach to rate cases. The approach we posit is something of a hybrid. Specifically, regulators consider costs in the year immediately before the rates are updated (including the up-front costs associated with cost reduction activities), and the cost savings that are expected in the next regulatory cycle because of initiatives that have already occurred. We therefore specify a *Corrected Costs* measure that includes these elements.

Regulators can use this corrected costs measure to update rates in two ways:

$$Revenue_t = Corrected\ Costs_{t-1}, \quad \text{or}$$

$$Revenue_t = \text{average}\left(Corrected\ Costs_{t-1}, Corrected\ Costs_{t-2}, \ldots, Corrected\ Costs_{t-k}\right).$$

The first is the common approach. The second uses multiple test years instead of just one.

A recent source of innovation in utility regulation has been the extent to which the regulator bases rate plan updates on the utility's own cost. To the extent that the rate update depends instead on external considerations, utilities get to keep a share of the benefits of their efforts to improve long term performance. Formulaic approaches to the externalization of rate plan updates are sometimes called efficiency carryover mechanisms (ECMs).

We allow efficiency carryover mechanisms to be implemented with a single test year or with multiple test years. The plan update equations are the following:

$$Revenue_t = (1-\gamma)Corrected\ Costs_{t-1} + \gamma b \qquad \text{(ECM, Single Test Year)}$$

$$Revenue_t = (1-\gamma)\text{avg}\left(Corrected\ Costs_{t-1}, \ldots, Corrected\ Costs_{t-k}\right) + \gamma b \quad \text{(ECM, Multiple Test Years)}$$

Here b is some cost measure that is unaffected by firm actions. It can be established by various means, including statistical benchmarking or a one-year extension of the expiring rate setting mechanism. The term γ is the externalization percentage. When $\gamma = 0$, costs are determined as they are in a standard rate case. When $\gamma = 1$, revenue is completely de-linked from firm behaviour, which is known as "full rate externalization."

2.2 Rate Option Plans

A different approach to rate updates is to allow utilities two options at the end of each update cycle: choose a standard rate case, or a "stretch factor" plan in which there is no rate case but rates decline predictably over the term of the next plan. The former choice allows the firm to keep most or all benefits of cost reduction before a plan update and none after. The latter choice avoids a full and immediate pass through of efficiency gains but compensates consumers with a stretch factor in the next plan that slows rate growth.

The stretch factors should reflect an allocation of the benefits of cost reduction between the utility and its customers. If the stretch factor is too high, the firm will always choose the standard rate case and will have relatively weak incentives to improve efficiency. If the stretch factor is too low, the firm will avoid rate cases and be more efficient but customers will only get a small portion of the benefit.

The rate update formulas depend on which option the firm chooses.

Should they choose a standard PBR, rates are set so that

$$Revenue_t = Corrected\ Costs_{t-1}$$

Should they choose to accept a stretch factor, rates are set as follows:

$$\begin{aligned}
Revenue_t &= Revenue_{t-1} - f \cdot costs_{t-1} \\
Revenue_{t+1} &= Revenue_t - f \cdot costs_{t-1} \\
&\vdots \\
Revenue_{t+term\ length} &= Revenue_{t+term\ length-1} - f \cdot costs_{t+term\ length-1} \\
Revenue_{t+term\ length+1} &= Revenue_{t+term\ length} - f \cdot costs_{t+term\ length-1}
\end{aligned}$$

We assume that the utility knows stretch factor f , and that it is constant through time.

Section 3: Quantifying Incentives

The regulatory plan is announced to the firm before it decides on the level of cost-reduction efforts. The manager is therefore aware of the values of earnings sharing, plan length, and the other regulatory parameters. The initial values of capex, opex, and capital stock are also known. The optimization problem in this model is to choose a sequence of efforts $\boldsymbol{\varepsilon}_t$ for each project to maximize the value of the firm's objective function (1) given the regulatory system.

Different plans can lead to different levels of cost reductions, and since they are modelled under the same framework, they can be compared to each other. For each plan we consider $NPVF_i$ (the net present value to the firm of all cost reduction projects), $NPVCB_i$ (the net present value of what customers get through reduced rates and earnings sharing), and $NPVX_i$ (the net present value of the additional tax revenue generated). The total net present value, or social welfare, of a plan is:

$$NPVT_i = NPVF_i + NPVCB_i + NPVX_i$$

The greater the firm's incentive to reduce cost, the higher $NPVT_i$ will be.
We consider two "polar" forms of regulation: the cost-plus regulation, under which no incentives for cost reductions are induced and $NPVT_i = 0$, and "full externalization" of future rates, whereby rates are fully de-linked from costs, even during rate updates. Full externalization produces maximal incentives, so we define $NPVT_{max} = NPVT_{fullextern}$.

We define the (relative) incentive power of a plan i as the ratio of $NPVT_i$ to the maximum $NPVT_{\max}$, which is achievable under the full-externalization plan,

$$IP_i = \frac{NPVT_i}{NPVT_{\max}} \times 100\%$$

We also measure the incentive power of each plan by computing the average performance gain during each rate case and during the duration of the model. These averages are computed using the measure:

$$performance\ gain_{\mathrm{s\ to\ t}} = 1 - \left(costs_f / costs_s\right)^{1/(t_f - t_s)}.$$

Here $costs_f$ is the cost level in time t_f, $costs_s$ is the cost level in time t_s, and $performance\ gain_{\mathrm{s\ to\ t}}$ is the rate of exponential decay that would explain the change in costs from $costs_s$ to $costs_f$ in time $t_f - t_s$. Note that this is a rearrangement of the geometric decay equation $costs_f = costs_s \left(1 - r\right)^{t_f - t_s}$.

Section 4: Parameter Choices

In calibrating the model, we bear in mind two major goals: a close match of economically significant parameters to the realities of modern regulation and the interpretability. In particular, the following constants were chosen to set initial values for the model:

- Cost of funds $r = 7\%$ so that the discount factor (β) is 0.93.
- Time horizon is 85 years. This is acceptable because cash flows 86 years out are discounted by $0.93^{86} = 0.003$.
- Depreciation rate $d = 5\%$.
- Tax rate $\tau = 30\%$.
- Initial capex = 275 million.
- Initial opex = 277 million.
- Initial revenue = 2515 million.
- Initial book value of equity (assets – liabilities) = 1448 million.
- Initial pre-tax earnings = 174 million.

The other parameters α, p and σ are calibrated to represent the following:

- We consider two types of opex or capex reduction projects: (1) initiatives that reduce costs permanently, and (2) one-off initiatives in a particular year.
- For permanent cost reduction initiatives we consider projects with payback periods of 1, 3 and 5 years with effort level of 1. The payback period is defined here as the number of years needed for the company to break even, i.e. the time when cost reductions will recoup the up-front costs related to the project.
- Capex and opex reductions are considered separately, which leads to 8 cases in total, or $J = 8$ in the formal framework.
- All 8 projects are available for pursuit by the company at different effort levels. The actual intensity of the projects undertaken and the choice of projects to pursue will depend on the utility's response to the regulatory regime. The final summary presents totals across all projects.
- Project parameters are chosen so that an effort level of 10 for each project produces the maximal benefit for firms under full rate externalization. They are also chosen so that a firm with 20% initial inefficiency will achieve a long run average annual performance gain of 1.0% under a 3-year cost of service plan.

- The implicit regulatory/nuisance of cost reduction initiatives (distress) comprises 20% of the explicit monetary up-front costs (UFC), i.e. $\sigma_{m,j} = 0.20 p_{m,j}$ and $\sigma_{n,j} = 0.20 p_{n,j}$.

The payback period measure is very important in the model. When it is higher than the term of the plan, the opportunities for cost reductions will not be pursued at all. If the payback period is lower than the term of the plan, most of activities will be pursued at the beginning of the plan, with incentives falling towards the end of the plan.

Section 5: Model Solution

Since the model is hard to handle analytically (especially given the variety of the plans), we wrote a computer procedure that searches over possible values of $\boldsymbol{\varepsilon}_{\mathbf{t}}$ to maximize the value of the objective function under a given plan (i.e., for specified values of plan length, γ, etc.) and computes and reports the resulting changes in capital, costs, and eventually the present values of profits, cost savings, and total social benefits. This procedure is run for as all plans of interest as specified by an input file, and the results for each plan are output into a text file.

To search for the optimal $\boldsymbol{\varepsilon}_{\mathbf{t}}$, we first make 100 random guesses and choose the one that gives the maximum value of the objective function. This first step gives us an initial approximation of the optimal $\boldsymbol{\varepsilon}_{\mathbf{t}}$. In the second step, we implement an iterative converging procedure similar to the “steepest gradient descent” method. The iteration process ends when the objective function evaluated at the current iteration of ε_t differs from the evaluation at the previous $\boldsymbol{\varepsilon}_{\mathbf{t}}$ insignificantly (by 0.001 or less).

Section 6: Application to Ontario

To determine a stretch factor for the regulatory plans of Enbridge and Union, we tested three and six-year cost of service plans, as well as a few reference plans, using the incentive power model. We then examined the resulting average performance gains (see section 3 for details) over the first rate cycle, second rate cycle, third rate cycle, and the entire time horizon (85 years). Complete results are in Table 1. Plans with efficiency carryover, earnings sharing, and different plan terms are also included for reference. We believe that the long run estimate is the most representative measure of the expected efficiency gain under a given plan. The results pertain to a firm with average operating efficiency.

The proposed regulatory plan will be a six-year plan, which the incentive power model predicts will induce long-run yearly cost reductions of 1.88% (highlighted in Table 1). In addition to the stretch factor, the price cap index includes a productivity differential that is based on results for utilities that operated with an average regulatory lag of three years during the sample period. The incentive power model predicts that firms operating with a three year lag will have yearly cost reductions of 1.01% (highlighted in Table 1). So firms under a system such as the proposed ARP will have average performance gains of

$$0.87\% = 1.88\% - 1.01\%$$

beyond those already incorporated into rates by the index. The research suggests a stretch factor of 0.44% would divide this surplus about evenly between the firm and consumers.

Table 1. Average Annual Performance Gain Under Different Plans

Initial inefficiency = 20%	**Average Annual Performance Gain**			
	1st Rate Cycle	2nd rate cycle	3rd rate cycle	Long run
Reference Regulatory Options				
2 Year Cost of Service	0.41%	0.44%	0.54%	0.70%
3 Year Cost of Service	0.85%	0.91%	0.98%	1.01%
Full Rate Externalization	5.63%	4.58%	4.45%	4.48%
Impact of Plan Term				
Term = 3 years	0.85%	0.91%	0.98%	1.01%
Term = 6 years	1.52%	1.55%	1.72%	1.88%
Term = 10 years	2.05%	2.41%	2.73%	2.53%
Impact of Earnings Sharing				
3-year plans, ESM				
No Sharing	0.85%	0.91%	0.98%	1.01%
Company Share = 75%	0.66%	0.70%	0.74%	0.86%
Company Share = 50%	0.53%	0.57%	0.64%	0.72%
Company Share = 25%	0.37%	0.46%	0.55%	0.59%

Witness: Mark Lowry

	Average Annual Performance Gain			
	1st Rate Cycle	2nd rate cycle	3rd rate cycle	Long run
6-year plans, ESM				
No Sharing	1.52%	1.55%	1.72%	1.88%
Company Share = 75%	1.24%	1.45%	1.58%	1.57%
Company Share = 50%	0.98%	1.16%	1.33%	1.36%
Company Share = 25%	0.92%	0.97%	1.09%	1.12%
Impact of Partial Plan Update Externalization				
3-Year Plans, Extern				
Externalized Percentage = 0%	0.85%	0.91%	0.98%	1.01%
Externalized Percentage = 10%	2.30%	2.27%	2.35%	2.77%
Externalized Percentage = 25%	3.84%	3.30%	3.35%	3.61%
Externalized Percentage = 50%	5.82%	4.03%	3.98%	4.11%
6-Year Plans, Extern				
Externalized Percentage = 0%	1.52%	1.55%	1.72%	1.88%
Externalized Percentage = 10%	1.90%	2.10%	2.29%	2.42%
Externalized Percentage = 25%	2.83%	2.96%	3.10%	3.26%
Externalized Percentage = 50%	4.14%	3.85%	3.89%	3.95%

Witness: Mark Lowry