

Power System Engineering, Inc.

PSE

Response to the Draft Report of the Board

The Coalition of Large Distributors (CLD)

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No Validation and Very Limited Review

- Board's Draft Report and PEG report came out last Friday afternoon (Sept. 6, 2013)
  - Two business days of review time before this conference
  - Not nearly enough time to validate PEG's model and findings
  - Not enough time to digest all of the data modifications and changes from PEG's May 2013 report to this modified report
- At this time, we cannot validate PEG's findings, model, data changes, or results

Board's Draft Report Items I will Respond To

- Two-factor IPI
  - 70% weight on GDP-IPI, 30% weight on AWE
- Productivity factor equal to zero
- Stretch factors ranging from 0.0% to 0.6% with an average of 0.37%
- Elimination of peer grouping in stretch factor calibration
- Solely use PEG's econometric model for stretch factor determination

Inflation Factor

- Board's recommendation is an improvement from PEG's recommendation (Two-Factor IPI)
  1. Far less volatility
  2. Better tracking of actual distributor cost pressures
  3. No need for 3-year smoothing making it more contemporary
- Still does not account for capital asset inflation (which is around 50% of utility cost pressures)
  - The index necessary for this is already tracked through the Electric Utility Construction Price Index (EUCPI)
  - Very simple to insert in a weighted average of the EUCPI and have a 3-Factor IPI
  - Better tracking of 50% of the inflation pressures

Two Suggestions for Improvement

1. Include weighted average of EUCPI to account for capital inflation
2. Consider updating the IPI with available indexes more than the once per year
   - January 1 filers will have an inflation factor that two years prior to the year it is being applied to
     - Even if AWE or EUCPI are only updated annually, the GDP-IPI component could easily be updated quarterly
   - Will make the inflation factor more up-to-date and applicable to the rate year

Productivity Factor

- 2002-2012 TFP has been measured to be negative
  - All four experts appear to agree that Ontario TFP has been negative
  - 11-year trend measured by PEG at -0.33% after excluding Hydro One and Toronto Hydro
  - Larger, in absolute terms, with full industry
- More recent TFP has been even more negative
  - PEG estimates 2006-2012 TFP of -1.28%
  - Even after stripping out certain smart metering expenses and only negative TFP “outliers”
- Trend Variable is now 1.98%

Productivity Factor

- Cost pressures and challenges placed upon distributors are not likely to dissipate (CDM, smart grid, FIT programs, aging infrastructure, etc…)
- Assuming cost pressures and challenges do not disappear, unit cost increases will substantially outpace IR rate increases with a productivity factor set at 0.0%
  - There is an implicit stretch factor if productivity factor is set at zero

Stretch Factor

- Should be recognized that there is an implicit stretch factor included in a productivity factor set at zero when considering the empirical evidence on the actual productivity trend
  - PEG estimates the shortfall between zero productivity and actual productivity at 0.33%
  - Other experts believe this number is much larger
- In addition to the implicit stretch factor, the explicit stretch factor averages 0.37% with a range of 0.0% to 0.6%
  - Total stretch factor is, **at a minimum**, ranging from 0.33% to 0.93% with an average of 0.70%
    - This is an extremely demanding stretch factor beyond the bounds of what is normally seen in incentive regulation plans

Determination of Groups

- Cohorts determined by by score
  - Tranche 1: <-20%, Tranche 2: -20% to -15%, Tranche 3: 0 to -15%, Tranche 4: 0 to 15%, Tranche 5: >15%
- This way of dividing the industry makes the groups vulnerable to the strength of the model and how much variance it contains
  - More variance (i.e. error) the more distributors will be in Tranche 1 or 5
- Dividing the industry into quintiles based on ranking would be simpler and assure an equal distribution that does not change over time

Suggestions on Stretch Factor

- In recognition of the implicit stretch factor in a productivity factor of zero, the stretch factor should be reduced
- Current method based on cost score is vulnerable to the inaccuracy of the model and the distribution could drastically change over time
  - Base the tranches on the rankings… 1st quintile = Tranche 1, etc…

Elimination of Peer Groups in Stretch Factor Determination

- Highly supportive of this
- Peer group method ignored crucial information, made the process more complex, and hampered distributors ability to move between stretch factors

Econometric Benchmarking Model

- Draft Report states the use of PEG's econometric model
- PSE previously put forth a unit cost econometric model
  - Board's primary concerns of PSE unit cost model
    1. Assumes linear relationship between business conditions and costs
    2. Assumes constant returns to scale

VARIABLE KEY

KM/N=	KM of Line per Customer
P/N=	Peak Demand per Customer
A/N=	Service Area per Customer
%GS=	Percent Large and General Service Loads
%N10=	Percent Customers Added in Last 10 Years
Wd=	Hourly Wind Sum Above 10 knots
%S=	Percent Single Phase Lines
LF=	Dummy for Canadian Shield
%UG=	Percent Lines Underground
%UG*N/A=	Percent Lines Underground times Customers per Area
Trend=	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM/N	0.270	24.01	%S	-0.076	-6.85
P/N	0.088	4.28	LF	-0.046	-1.79
A/N	0.051	10.27	%UG	-0.366	-11.25
%GS	0.122	6.34	%UG*N/A	0.001	26.91
%N10	0.134	17.55	Trend	0.015	14.85
Wd	0.020	2.82	Constant	7.153	98.58

Concern #1 of PSE Model

- Linear relationship assumed
  - Not true in the PSE Report filed in June
  - In response to the last stakeholder conference when Professor Yatchew and Dr. Kaufmann raised this concern, we changed the model specification in the report to a log-log form
    - Variables are not assumed to be linearly related but rather logarithmically related
      - Same assumption that PEG’s model makes

Concern #2 of PSE Model

- Assumes constant returns to scale
- What does that assumption mean?
  - It means that the model assumes that if output increases by 1% then costs will also increase by 1%
    - Very similar to the assumption of TFP growth equaling zero
- What is PEG’s model calculating?
  - PEG’s translog cost function remains “flexible” on this assumption
  - Leads to obviously wrong underlying assumptions of returns to scale

PEG's Model Returns to Scale Results

- Unlike PSE model, PEG model is not making the same returns to scale assumptions for each distributor

<u>Some examples</u>

- Cost elasticity of customers for Hydro One is -0.514
  - PEG's model assumes that if Hydro One increases its customers by 1% its costs will **<u>drop</u>** by 0.514% (violates economic theory)
- Cost elasticity of customers of Hearst Power is 1.366
  - PEG's model assumes that if Hearst Power increases its customers by 1% its costs will increase by 1.366%.
- Wasaga Distribution's cost elasticity of customers is 0.045
  - 1% increase in customers estimated by PEG model to **<u>only</u>** increase costs by 0.045%

- Again, PSE model says that a 1% increase in output increases costs by 1% for all distributors
  - This is a far more reasonable assumption to make

More Examples of PEG Model Assumptions

- PEG model assumes that if Wellington North Power increases peak demand by 1% its costs **drop** by 0.297% (violates economic theory)
- PEG model assumes that if Sioux Lookout Hydro increases kWh sales by 1% its costs **drop** by 0.109%.
- Not isolated examples
  - 32 out of 73 distributors have negative returns to peak demand in model
  - 15 out of 73 distributors have negative returns to kWh sales in model
- Violates economic theory and intuition

Advantages of PSE Model Over PEG's

1. Constant returns to scale assumption
   - Does not violate economic theory and common sense
   - Treats all distributors equally
2. More statistically significant business conditions included in the model
   - PEG model has six, PSE model has ten
3. No insignificant business conditions included in the model
   - PEG model has two business conditions that are not statistically significant % area, % lines underground
     - PEG also has a number of other terms (quadratics and interaction terms) that are not statistically significant

Summary

- Board’s Two-Factor IPI is superior to PEG’s recommendation but can easily be enhanced by including the EUCPI
- Productivity factor of zero is not reflective of the recent historic experience of Ontario and embodies an implicit stretch factor
- Draft report stretch factor calibration can be improved by using the rank rather than the score
- The implicit stretch factor in the productivity factor should be recognized in a reduction of the stretch factor
- PSE econometric model is a better and more intuitive model to use for benchmarking purposes

Thank You! Questions?

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