STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2013-00168

CENTRAL MAINE POWER COMPANY
REQUEST FOR NEW ALTERNATIVE RATE PLAN
("ARP 2014")

REBUTTAL TESTIMONY
Productivity

February 4, 2014

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CENTRAL MAINE POWER COMPANY

Docket No. 2013-00168

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I. INTRODUCTION

Q: Please state your name, title, and business address.

A: My name is Mark Newton Lowry. I am the President of Pacific Economics Group ("PEG") Research LLC. My business address is 22 East Mifflin Street, Suite 302, Madison WI 53705.

Q: Have you filed direct and supplemental testimony in this proceeding?

A: Yes. My direct testimony discussed the various approaches to the design of attrition relief mechanisms ("ARMs") for alternative rate plans ("ARPs") that feature revenue decoupling. I also discussed research I performed for Central Maine Power ("CMP" or "the Company") on the operation and maintenance ("O&M") price and productivity trends of Northeast power distributors. The Commission rejected CMP's proposal for a "hybrid" revenue escalator in which index-based escalation for O&M revenue was paired with a stair-step trajectory for capital revenue that would be based on a multiyear cost forecast.

My supplemental direct testimony presented research on the multifactor input price and productivity trends of Northeast distributors. This supported the Company's proposal for a comprehensive revenue cap index ("RCI") featuring a negative X factor. This research followed Maine's tradition in ARP filings of breaking down the X factor into productivity differential, input price differential, and stretch factor components. CMP's proposed X factor also included a fixed customer growth term and a K factor that would provide CMP with supplemental revenue to help fund an accelerated program of system modernization.

Q: What is the purpose of your rebuttal testimony?

A: I wish to rebut certain representations in Staff's Bench Analysis and the testimony of Office of Public Counsel ("OPA") witness Charles King concerning my supplemental research and testimony and the appropriate design of an RCI for CMP. In particular, Staff has taken issue with the sample period and peer group for my index research; my K factor calculations; and my advocacy of a 0% stretch factor, a 0.37% customer growth factor, and, more generally, a negative X factor.

Q: Please summarize your testimony.

A: CMP has operated for many years under ARPs with price cap indexes. The X factors of these indexes have reflected research on the input price and productivity trends of Northeast electric utilities. CMP has responded to the strong incentives ARPs provide with superior productivity growth. The Company has been a particularly good capital cost performer. Customers will receive the full benefit of CMP's low current capital cost in this rate case.

The Company's capex requirements will be higher in the next few years. This makes the terms of the new ARM critically important to CMP's ability to continue operating under an ARP. A price cap index might not provide sufficient revenue growth in an era of slow volume growth, and would also discourage innovative rate designs that can complement state demand-side management ("DSM") programs. There is, additionally, the risk that the X factor will not properly reflect recent input price and productivity trends, which point to a lower X factor than in years past. Additionally, I have performed innovative but rigorous research to support an additional adjustment to X to reflect CMP's historically good capital cost performance.

Neither Staff nor OPA witness King have provided convincing arguments for rejecting the Company's proposed X factor. In particular, I show in my testimony that

- The proposed sample period strikes a sensible balance between the needs to smooth index volatility, avoid data problems, and reflect future operating conditions.
- The Commission should continue to base X on trends for a Northeast peer group. An

upper Northeast peer group, which Staff has traditionally favored, would as Staff concedes produce a negative X factor.

- There are strong grounds for a 0% stretch factor, and no grounds for an unusually high one.
- My evidence, which includes a high quality capital cost benchmarking study, points to the need for a supplemental K factor adjustment.
- Escalation of allowed revenue for customer growth is supported by reason and precedent.

Taken as a whole, my testimony provides the Commission with the grounds to approve an X factor that would permit CMP to continue to pursue system modernization without abandoning alternative rate plans for a return to frequent cost of service rate cases.

II. BENCH STAFF ANALYSIS

A. Negative X Factor

Q: Let's begin the discussion of Staff's Bench Analysis by discussing their concern over the Company's proposed negative X factor. Staff states on page 94 of the Bench Analysis that "there are no distribution utilities in the U.S. with similar style ARPs that feature a negative productivity offset. In fact, as also shown in that same data response, of all utilities that have had similar style ARPs, only one, a government-owned utility in Australia, has ever had a negative X factor." How do you respond?

A: Staff is referring here to ARPs with X factors calibrated using index research to reflect industry cost trends. While their statements are accurate, the precedents for ARMs based on index research must be interpreted cautiously to glean lessons appropriate for CMP.

- Let me begin by noting that there are only two distribution utilities in the United States which operate under ARMs with X factors that emanated from hearings where industry cost trends were considered. One of these is CMP, whose X factor was designed for a price cap index under business conditions different from today's.
- Staff's comments are restricted to distributors, but the major use of ARPs with index-based ARMs in the United States is in the regulation of oil pipelines. The U.S. Department of Transportation has adopted safety regulations that have imposed significant obligations and considerable compliance costs on these pipelines. The Federal Energy Regulatory Commission has twice approved negative X factors for oil pipelines and the current value of X is -2.65%. In approving a negative X factor for the pipelines in 2006, the FERC stated that

> we disagree with Shippers that the pipelines can expand their systems and handle environmental, safety and security measures based on the present [ARM], without any need to increase that index. The ability of pipelines to accomplish what Shippers claim they have in terms of system expansion and environmental, safety and security measures is due in no small part to the appropriateness of the current index level. There is no guarantee that in the future pipelines will retain that ability unless the Commission once again adopts an index that allows the pipelines to recover their expected cost increases.[1]

- ARPs with X factors informed by index research are more common in Canada than in the US today. All power distributors in Alberta and Ontario, for example, operate today under ARPs with index-based ARMs and provisions for supplemental capital funding. The X factors in these plans must be interpreted cautiously. The new ARMs in Alberta and Ontario feature custom utility inflation measures rather than a macroeconomic index such as the GDPPI. The X factors in the Canadian plans did not, then, need to be adjusted for the MFP trend of the economy. The MFP trend of Canada's economy has, in any event,

[1] FERC, Five Year Review of Oil Pipeline Pricing Index, Order Establishing Index for Oil Price Change Ceiling Levels, Docket No. RM05-22-000, March 21, 2006, pp. 36-37.

been negative on average over the last decade. The 1.16% X factors for Alberta energy distributors would be virtually zero if reduced by the recent MFP trend of the US private business sector. The 0.30% average X factor in the new ARP for Ontario power distributors would be close to -0.81%.

- The X factor proposed by CMP is reduced by 37 basis points for customer growth. The Company could easily have proposed a stand-alone customer growth term for its RCI or designed it as a revenue per customer index. An X factor based solely on index results for a traditional upper Northeast data peer group would then be -1.53%. An X factor based on broad Northeast data would then be -0.65%.
- It is difficult for any distributor to finance increasing investment need when the X factor is based on the long-run productivity trend of the industry. Utilities nonetheless occasionally need additional investment. For this reason, a high percentage of contemporary ARPs with X factors based on index research include capital cost trackers that can provide utilities with supplemental funding for high capex. These include the ARPs in Alberta, Ontario, and Vermont, as well as the expiring ARP for CMP.
- As I explained in my direct testimony last May, many ARPs have ARMs that are not based on index research. Escalation is instead achieved via stair steps, hybrids of indexing and stair steps, or British-style ("RPI – X") indexes that are based on multiyear cost forecasts. All of these alternative approaches to ARM design have the potential to fund high capex. ARMs with British-style indexing have featured negative X factors on numerous occasions.
- The Commission in its July decision rejected the idea of a stair-step, forecast-based revenue requirement trajectory for capital, and would presumably also not favor a broad-

based capital cost tracker for CMP. Faced with the difficult choice of frequent rate cases or an ARP with a negative X factor based on rigorous cost research, the Company has chosen the latter.

B. Sample Period

Q: Let's turn next to your choice of a 2002-2011 sample period for your index research. Staff speak on page 96 of the Bench Analysis of "a basic weakness in the analytical approach . . . The approach establishes an index for each year *in the future* . . . based upon a formula for which key component parts are based upon *the past*, . . . assuming that observations of the recent past reliably predict outcomes over the next five years. . . . it raises issues as to whether the historic time period used is representative of the future time period, and whether any adjustments are appropriate to recognize that the future will not look exactly like the past." How do you respond?

A: The methodology Staff describes is, of course, the traditional one for calibrating X factors. It has been used in Maine since the very first ARP was approved for CMP in the 1990s. A base productivity growth target is established that reflects the long-run historical productivity trends of other utilities yet is pertinent to the prospective term of the ARP.

One means of making historical productivity calculations more pertinent to the future is to make them less sensitive to short term productivity fluctuations that aren't likely to continue. Several steps we have taken in our study for CMP accomplish this goal. Expenses for uncollectible bills and customer service and information (the latter dominated by DSM expenses) were removed from the calculations because they rose rapidly during the sample period and are unlikely to continue doing so prospectively. Consider also that we measured output by the number of customers served, which is much less volatile than delivery volumes.

Concern as to whether the past will be prologue to the future is still a valid consideration in ARM design. However, the remedy is not always to extend the sample period backwards. Slowing productivity trends may, for instance, be a temporary deviation from a long term trend or the start of a new trend. Exceptionally long sample periods may not capture current trends in production technology, scale economies, and the average use of power. Longer sample periods may also involve data quality problems.

In the case of input price inflation, a case can be made for tracking *medium*-term trends, which can deviate for several years from the very long-term trend. To see why, consider that the central insight of performance-based ratemaking ("PBR") is to use industry price and productivity research to reduce utility operating risk in a way that extends the period between rate cases and strengthens rather than weakens utility performance incentives. I explained in Section 2.2.6 of my supplemental testimony that ARMs based on index research typically capture *current* macroeconomic input price inflation, but also contain an X factor adjustment for the difference between the longer-run input price trends of the industry and the economy. This reduces risk and the need to calculate complex industry input price indexes annually. Basing input price differentials on trends over the last 10 years, whether or not this captures the very long-term trend, causes the ARM to track some of the deviations of input prices around the long-term trend, thereby reducing utility operating risk without weakening performance incentives or requiring the annual calculation of sophisticated utility input price indexes.

This point is meaningful because the input price trend of Northeast power distributors exceeded that of the economy by 0.24% (for the broad Northeast) and 0.35% (for the upper Northeast) during the featured sample period due, chiefly, to rapid growth in the regional construction cost index. Recognition of modest negative input price differentials would help CMP fund its cost growth and continue operation under ARPs. A negative input price differential was the key reason for the negative X factor Staff noted for a PBR plan in Australia's Northern Territory. The sample period for this calculation was only six years.

Q: Staff notes on pages 96-97 of the Bench Analysis that the X factor might differ if the Commission were to reject the Company's revenue decoupling proposal and instead insist that the ARP feature a price cap index. Is that true?

A: Yes. To understand why, please note first that revenue cap and price cap indexes based on index research are both intended to yield revenue growth that is in line with cost growth. A basic result of cost theory is that cost is a function of operating scale. Cost growth thus depends in part on growth in operating scale. A revenue cap index addresses this issue with an allowance for growth in the Company's own operating scale. As discussed further below, it is sensible to represent cost growth by growth in the number of customers served.

A price cap index, in contrast, addresses only the escalation in *rates*. Growth in the utility's revenue also depends on the growth of its billing determinants. For an energy distributor operating under traditional rate designs, this is chiefly a matter of growth in the volumetric and other usage charges of residential and commercial ("R&C") customers. If revenue growth is to be commensurate with cost growth, a key issue in the choice of an X factor for a *price* cap index is then the tendency of R&C system use to grow at a different rate than the growth in customers. This is the same as the growth in R&C average use. This issue is addressed by using a revenue-weighted billing determinant index to measure output growth since this would place a heavy weight on volumes and

growth volumes = *growth customers* + (*growth volume* – *growth customers*)

= *growth customers* + *growth volume/customer*.

Growth in R&C average use has slowed markedly for CMP and many other utilities in recent years due to slow economic growth and the ramp up of DSM programs. In my 2007 testimony for CMP, for instance, the 1.49% trend in the volume of residential customers compared to a 0.78% customer growth trend. In contrast, CMP's R&C customers are forecasted to experience declining average use during the term of the prospective new ARP.

This has a number of implications for index research.

- Slowing growth in average use would tend to reduce the X factor appropriate for a price cap index for CMP from the level that would have been appropriate in 2008.
- The X factor appropriate for a *price* cap index for CMP is likely to be lower than the X factor for a *revenue* cap index.
- Since the slowdown is fairly recent, it would be difficult to find a sample period of at least ten years, which we would wish for index smoothing, in which Northeast utilities experienced declining average use of power. Extending the start date of the analysis further into the past would not remedy the problem since average use also grew more rapidly in the past.

Q: Staff notes on page 100 of the Bench Analysis that NERA Economic Consulting prefers to use the longest time period possible when testifying on industry price and productivity trends. Why is that?

A: NERA's indexing methodology differs from the one I used in my research in ways that make input price and productivity indexes unusually volatile.

- Output indexes use only volume variables and these variables are unusually sensitive to volatile demand drivers such as weather and the business cycle.

- The "one-hoss shay" approach to capital costing values capital in current dollars. Capital cost is thus computed net of capital gains and this imparts volatility to the input price index.

Additionally, the multilateral quantity indexes that NERA uses are less effective than chain-weighted indexes in measuring quantity *trends*, especially in the earliest and latest years of the sample period. Long sample periods are thus needed with NERA's methodology in order to calculate long run productivity trends. In Docket 99-666, Staff stated on page 45 of their Bench Analysis that one of the flaws in NERA's study was that "the time period of the sample is too long".

The volatility of NERA's productivity index was a major source of controversy in the recent Alberta proceeding that Staff mentions. The last year of the sample period in NERA's study was 2009, at the bottom of the recent severe recession. For this and other reasons, NERA reported a *negative* MFP trend for US power distributors in the later years of the sample period. From 2002-2009, for example, NERA reported a -0.73% average annual growth rate in the MFP of distributors in its national sample. Staff reported a 0.80% trend in its national sample over the same years in this year's Bench Analysis.

Q: Staff notes on page 100 of the Bench Analysis that you stated in the same Alberta proceeding that recent empirical results and NERA's testimony persuaded you that a minimum sample period of 15 years is typically desirable for indexing work and that "a longer time period would help mitigate any skewing effect that the severe recession of 2008-2009 would otherwise have on the results". Staff also claims that you recommended to the Alberta Commission that the recession years 2008 and 2009 be excluded from the analysis, thereby highlighting the severity of the recession and its impact on potentially

skewing results. How do you respond?

A: I was retained by an Alberta consumer group in 2011 to comment on NERA's power distribution productivity study and also to prepare a companion gas productivity study. At the time, the latest year for which data were available for a gas indexing study was 2009. Productivity trend estimates are particularly sensitive to events in the first and last year of the sample period. Unusual care was thus warranted to make sure the results were not unduly sensitive to the effects of the recession. A fourteen year sample period seemed warranted for my study in that context. My recommendation to exclude 2008 and 2009 data pertained to *NERA's* study because of its much more volatile output index.

In my study for this proceeding, I have been able with the passage of time to extend the sample period from 2009 to 2011. The sample thus includes two years of recovery from the recession. In these two years, productivity growth has not reverted to the norm of earlier years, due in part to sluggish customer growth that slows realization of scale economies. Sluggish customer growth is expected to continue.

Using data for earlier years also involves practical problems. The 1995-2002 period was one in which many Northeast electric utilities sold or spun off generation assets. This complicates the allocation of general costs, and this was a source of controversy in CMP's ARP 2008 proceeding. A start date as early as 1995 or 1993 would also require us to "patch" together customer data from Form EIA 861 and FERC Form 1.

Considering all of these factors, I believe that my choice of the ten-year 2002-2011 period strikes the right balance between the needs for productivity index smoothing, quality data, and relevance to future business conditions. A ten-year period also produces an inflation differential that permits the ARM to track some of the fluctuation in utility input prices around the very long-term trend.

Q: Staff presents in Table 23 on page 101 of the Bench Analysis some productivity trend results for a longer sample period than you featured in your testimony. It states on page 101 that the results of the table "are illustrative only because of the blending of Dr. Lowry's prior and current analyses, which are not completely comparable." Are Staff's blended results useful?

A: No. Results of my productivity studies in the current and past proceedings cannot be blended constructively due to important differences in the indexing methodologies. One important difference is that CMP was then proposing a *price* cap index rather than a *revenue* cap index. The appropriate output index was therefore a revenue-weighted index of trends in billing determinants. This reflected the material growth in average use by residential customers that Northeast power distributors used to experience. As I discussed earlier in this testimony, growth in average use has slowed appreciably in the last five years and is expected to be negative for R&C customers of CMP prospectively. The trend in average use is, in any event, irrelevant to the design of a revenue cap index.

Note, secondly, that extending the sample period backwards to fifteen years does not materially affect the *productivity* differential. For the upper Northeast, for instance, it doesn't change. The chief effect of going to fifteen years is instead to flip the *input price* differential from a modestly negative value to a sizable positive value. This also involves a blending of apples and oranges. To illustrate the problem, consider that the methodology I employed in my 2007 testimony produced a sizable 12.96% input price differential for the upper Northeast in 2001 but this was offset by a -7.23% differential in 1993 and a -4.91% differential in 2003. In the new study, however, the input price differential for 2003 is only

-0.97%. Staff used my newer numbers for all years available.

Consider also that I reported a slight -0.013% input price differential for the full 1994-2005 sample period in my earlier study and a -0.35% input price differential for the full 2002-2011 sample period in my latest study. Yet somehow, in blending the studies, Staff has produced a 0.31% input price differential for the 1993-2011 sample period. It is notable that if we calculate a blended result for the upper Northeast using numbers from my *older* study rather than the new study for all years available we obtain a -0.27% input price differential.

I note, thirdly, that Staff has produced blended results for a Broad Northeast and National samples even though I did not present results for these samples in my earlier CMP testimony. They have, evidently, used upper Northeast results for the earlier years in their broad Northeast and US "blended" calculations. All in all, Staff's blended results are clearly not of sufficient quality to be useful in setting the X factor for CMP in this proceeding.

C. Relevant Peer Group

Q: Let's turn now to the related issue of the appropriate peer group for the indexing work. On page 98 of the Bench Analysis, Staff presents MFP results for a national utility sample. Please discuss the relevance of these results.

A: There is nothing wrong with Staff considering the national productivity trend as a "sensitivity" analysis in this case, as it has done in the past. However, peer groups drawn from the Northeast region have traditionally been used, for good reason, to calibrate the X factors of CMP and other New England utilities. The rationale is that utilities in the Northeast face input price trends and productivity growth drivers that differ from those nationally, so that a regional peer group reduces windfall gains and losses that needlessly increase operating risk. Staff has advocated the use of a Northeast peer group on several occasions, and has tended to advocate peer groups confined to the *upper* Northeast. In Docket No. 99-666, for example, Staff stated a preference for a New England peer group. At a time when CMP wants to continue operating under ARPs despite challenging conditions, it is surprising to me that Staff would seriously consider ignoring Northeast price and productivity trends that would ease the Company's attrition without weakening performance incentives or abandoning traditional X factor research methods in Maine.

Q: Staff maintains on page 98 of the Bench Analysis that CMP prefers the Broad Northeast peer group. Is that true?

A: Not in the context of the Company's revised proposal. As I mentioned earlier, CMP proposed a "hybrid" revenue cap escalator last May, in which indexing would apply only to O&M revenue while capital revenue would rise in forecast-based stair steps. Although the Company's investment plan includes some "smart grid" facilities, there was no provision to net off any O&M productivity gains that might be stimulated by this capex. O&M productivity grew much more rapidly in the broad Northeast than in the upper Northeast during the sample period, due in part to infrequent rate cases and numerous mergers. CMP advocated a broad Northeast peer group in that filing as a means of ensuring that customers received, through the X factor, the benefits of brisk O&M productivity growth.

A broad Northeast peer group is less preferable in an X factor applicable to *total* cost. CMP accordingly did not indicate a preference for the Broad Northeast in its supplemental testimony. Instead, it proposed an X factor between those indicated by the results for the broad Northeast and upper Northeast peer groups.

Q: Staff states on page 99 of the Bench Analysis that "Because the inflation factor to be utilized in the ARP formula does not account for regional differences in input price

inflation, a national sample set could be preferable." Do you agree?

A: No. I explained in Section 2.2.4 of my supplemental testimony that differences between national and regional price trends are one possible cause of an input price differential. Any such difference is reliably reflected in the input price differential I calculated, and should be so reflected. Input price differentials are a common feature of ARP filings in Maine. For example, I have routinely calculated them in my research and testimony for CMP, and Staff computed an input price differential in its 2007 Bench Analysis. In this proceeding, I found that the input price differential was material over the last ten years in the Northeast, and recognition of this finding would help the Company finance accelerated modernization.

D. Stretch Factor

Q: Let's turn now to the stretch factor issue. On page 106 of the Bench Analysis, Staff says that "it is generally recognized that a 'stretch factor' should be added to the base productivity factor when implementing a multi-year ARP." Do you agree?

A: No. I believe that a stretch factor is typically warranted only when there is reason to believe that the MFP growth of the utility will differ from the base productivity growth target that is established using index research. A utility's productivity growth may in principle be expected to be higher, the same, or lower than the target. For example, a negative stretch factor might be warranted if the subject utility were a superior cost performer and the ARP did not offer performance incentives any stronger than the typical utility in the productivity sample. This Commission approved a zero stretch factor in a 1990s ARP for Bangor Hydro.

In this proceeding, CMP has been found, using rigorous research methods, to have achieved unusually rapid MFP growth for more than a decade and to have had a superior recent capital cost performance. The proposed ARP is not likely to contain performance incentives superior to the regulatory environment in which the sampled utilities operated during the sample period. There are thus legitimate grounds for a 0% stretch factor. This argument is all the stronger should the Commission deny the Company's proposed K factor.

Q: Staff states on page 107 of the Bench Analysis that "If the base productivity factor is determined using companies that do not have ARPs, the productivity for the company with an ARP will be understated. In general, the utilities in the sample groups used by CMP and Staff have not operated under ARPs." Do you agree?

A: No. I believe that the frequency of rate cases and the presence or absence of earnings sharing mechanisms are the chief determinants of incentive power. The frequency of rate cases in the sample was lower than the term of the proposed ARP, especially in the Broad Northeast. Several sampled companies in New York and New England did operate under ARPs. Others operated, in the early years of the sample period, under restructuring-related rate freezes. Favorable operating conditions permitted some utilities to stay out of rate cases. For example, numerous utilities were involved in mergers and some utilities had rates that reflected the higher rates of return on equity prevalent before the rate freezes that were occasioned by restructuring. Furthermore, most utilities did not operate under earnings sharing mechanisms. The MFP trend of the sample thus reflects performance incentives that were comparable or possibly stronger than those of the proposed ARP.

Q: Staff presents some statistical benchmarking work to support its position on the stretch factor issue. What is your general view of this use of statistical benchmarking to help set stretch factors?

A: I believe that statistical benchmarking can play a useful role in establishing stretch factors for ARPs. I and other members of my staff at PEG have filed utility benchmarking studies in many proceedings, including some in which the stretch factor term of an ARM was at issue. For example, we have twice developed cost benchmarking methodologies for the Ontario Energy Board which the Board has used to set stretch factors in the ARPs for Ontario power distributors.

Q: What benchmarking methods are appropriate for use in an ARP proceeding?

A. Benchmarking studies that have a dollars and cents impact on the finances of utilities and their customers should be of testimony quality. Cost is a function of input prices as well as operating scale, and may also be affected by miscellaneous other external business conditions. Cost benchmarks should reflect the typical impact of local business conditions on the cost of the subject utility.

Econometric research on power distribution cost has found the determinants of cost to be numerous. A study that I published in the *Energy Journal* is illustrative.[2] Input prices, the number of electric customers served, the retail delivery volume, distribution line miles, the number of gas customers, the extent of undergrounding, system age, temperature, and precipitation (a proxy for forestation) were all found to be statistically significant cost drivers.

Information of this kind is useful in the selection of a benchmarking peer group. Additionally, econometric estimates of output elasticities can be used to compute unit cost indexes in which the various scale variables receive weights that are commensurate with their estimated cost impacts. Most importantly, an econometric cost model fitted with values for the cost-driver variables which reflect the business conditions faced by the subject utility can provide a useful cost benchmark. If there are multiple scale variables, the parameter estimates for these variables reflect their relative cost impacts. Another advantage of

[2] Mark Newton Lowry, Lullit Getachew and David Hovde, "Econometric Cost Benchmarking of Power Distribution Cost" *Energy Journal*, July 2005

econometric benchmarking is that it is possible to test the hypothesis that the utility is an average cost performer, and thereby to identify companies that are *significantly* superior (or inferior) performers at a certain (e.g. 90%) confidence level. It is usually not possible to draw such a conclusion when the difference between actual cost and the model's prediction is small. This in my opinion is the most accurate benchmarking methodology, so I have used it in my K factor research.

Q: Has econometric benchmarking been used in other ARP proceedings?

A: Yes. For example, both of our benchmarking studies for the Ontario Energy Board employed econometric benchmarking. The first of these studies also compared unit costs using peer groups, as Staff did in their Bench Analysis. However, the seventy plus companies in the Ontario sample were carefully sorted into peer groups based on similarity of business conditions. The choice of these peer groups was guided by the econometric work. Note also that the performances of companies in the peer groups were compared using unit cost indexes in which the output metrics had econometrically-based weights so that their relative importance as cost drivers was recognized. In its recent decision finalizing a new ARP for power distributors, the Board stated that it

> has decided to rely solely on the econometric model to assign stretch factors to distributors. In general, there is lack of support amongst stakeholders for the use of peer groups and the Board finds the reasons cited compelling. In particular, stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations. The Board notes that unit cost comparisons can still be done without pre-defining peer groups. The Board expects that the use of one benchmarking model to produce a single efficiency ranking will be more transparent and understandable for customers and distributors. Consequently, it should be easier for a distributor to identify its relative cost efficiency, act to improve it, move up the efficiency ranking and be rewarded through the annual group assignments by moving into a more efficient group.[3]

[3] Ontario Energy Board, 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. 20.

Q: Staff benchmarks CMP's cost performance over the 2009-2011 time period using capital and O&M cost per customer and capital and O&M cost per MWh. Is this study of sufficient quality to shed light on the right stretch factor for CMP?

A: No. Staff is to be commended for gathering benchmarking evidence, which is potentially germane, but the benchmarks in their study are simple unit cost metrics that control for only two of the many external business conditions that affect CMP's cost: customers and MWh. Numerous potentially important cost drivers are ignored, including input prices, precipitation, and the number of gas customers served. Furthermore, the cost per customer and cost per MWh metrics are presented without any information as to which scale variable is most important. Results are presented for a national as well as an upper Northeast peer group without any indication of which is more relevant.

Q: Are some of the results Staff presents more useful than others in shedding light on CMP's recent performance?

A: Yes. First of all, total-cost results are more pertinent than the results for individual cost categories such as O&M expenses. Total cost is what ultimately matters to customers, and high O&M expenses can go hand in hand with low capital costs. CMP's distribution O&M expenses were, furthermore, elevated during the sample period by severe storms and the five-year vegetation management program that began in 2009. Cost per customer comparisons are more relevant than cost per MWh comparisons because the number of customers served is a much more important cost driver. I also believe that the unit costs of the Upper Northeast utilities are more pertinent benchmarks than those for the national sample because they better reflect the cost drivers faced by CMP.

The most concrete result from Staff's benchmarking work is therefore that the total cost per customer of CMP was very similar to that of the Upper Northeast peer group in recent years. Given the imprecision of the exercise, the results are consistent with the notion that CMP is at least an average cost performer. It cannot be ruled out that the Company is a superior cost performer. Meanwhile, we have established using more rigorous methods that CMP achieved superior productivity growth during the period 2002-2011 and that it is a superior capital cost performer.

Q: Staff recommends on page 107 of the Bench Analysis a stretch factor for CMP that would place it in the upper quintile for productivity. Is this a reasonable proposition?

A: No. The evidence presented in this proceeding is, first of all, insufficient to ascertain CMP's distance from a top quintile cost level. It is possible that CMP *is* a top quintile cost performer. Even if it isn't, Staff has not provided any basis for believing that an upper quintile standard is reasonable. For example, O&M expenses are known to be volatile, and the unit cost of upper quintile utilities in Staff's sample is apt to reflect results for utilities that had temporary dips in O&M expenses during the sample period. A top *quartile* or top *tercile* goal is more reasonable, but the evidence is insufficient to make even these goals operational in X factor selection. Basing stretch factors on well intended but crude benchmarking studies can materially raise CMP's risk of operating under an ARP.

E. <u>K Factor</u>

Q: Let's turn now to the K factor issue. Staff states on page 85 of the Bench Analysis that "By the K factor proposed . . . the Company has, in essence, reverse engineered the results of its CRM. This again places the Commission in the position of having to judge the reasonableness of CMP's five-year projections of O&M and capital spending in order to assess the reasonableness of CMP's ARP proposal." On page

102 Staff states that "the purpose of the K factor is to generate additional revenue for CMP's projected capital spending . . . In this sense, it is not unlike CMP's originally proposed approach, which was rejected by the Commission." Do you agree with these statements?

A: No. My K factor methodology is expressly designed to *avoid* reliance on multiyear capital cost forecasts. It is based instead on the typical productivity trend of utilities with superior capital cost performance. The research methodology is not unlike using statistical benchmarking of *total* cost, as Staff has, to ascertain the correct stretch factor. There is general agreement that a favorable benchmarking study reduces the need for a stretch factor. If Staff had found in its benchmarking study that CMP was a top quartile performer, the Commission would not be compelled to *forecast* the Company's cost in order to grant it a low stretch factor.

Q: Are K factors widely utilized?

A: I mentioned above that many utilities in Australia and Britain have operated under index-based ARMs with negative X factors that reflect high capex forecasts. A list of multiyear rate plan precedents provided to Staff in response to EXM-019-009 showed that more than 40 plans have been approved with negative stretch factors. Other ARPs provide supplemental revenue for capex via cost trackers. The K factor methodology used in this proceeding has been developed as an innovative response to a situation in which a utility has an unusual need for non-revenue producing capex but the Commission prefers not to address this need via a tracker or stair step revenue escalator based on capex forecasts.

Q. On page 102 of the Bench Analysis Staff quotes NERA as stating in the Alberta proceeding that "K factors are generally not included in PBR plans because they can dampen efficiency incentives."

A: NERA witness Jeff Makholm was here using "K Factor" in a general sense that encompassed conventional capital cost trackers. He stated, for example that "All proposals (of the Alberta utilities in the proceeding) include capital expenditure (capex) provisions that, following the lead of some applicants, we label as *K-factor*s. The general purpose of *K-factor*s is to flow through capital expenditures into rates[4]." Designs for cost trackers sometimes do weaken performance incentives. Dr. Makholm, in any event, endorsed in that proceeding the idea of adding capital cost trackers with carefully defined eligibility criteria to ARPs when needed to provide supplemental revenue. He stated, for example that "Numerous regulatory bodies have adopted infrastructure trackers (see Section D.) for specific capital expenditures, and that is the approach we recommend here."[5]

The K factor proposed by the Company, on the other hand, is based on industry productivity trends and would be insensitive to the capex that the Company achieves during the term of the next ARP. It in no sense "flows through" capital cost into rates. The Company is thus incented to contain its capex, much as capex containment incentives seem to have been strong under British-style ARMs which, despite being based on cost forecasts, have predetermined X factors that do not rise and fall with spending during the ARP. If anything, the K factor would strengthen CMP's capital cost performance incentive since, if the Company continues to achieve reliability targets without high capex, it might be eligible for another K factor in its next ARP. In much the same manner, a stretch factor based on statistical benchmarking would encourage a utility to continually achieve superior performance.

Q: What of Staff's comment on page 102 of the Bench Analysis that the Ontario Energy

[4] Jeff Makholm and Agustin Ros, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative", February 22, 2012 p. 36.

[5] *Ibid* p. 51.

Board rejected the use of a K factor?

A: Staff references the Board's rejection of capital cost trackers in its 2006 decision approving a second generation PBR plan for Ontario's power distributors. I was the Board's ARP advisor in that initiative, and colleagues at PEG have advised the Board on subsequent ARPs. The second-generation ARP was intended to provide escalation for rates during a brief interim period in which distributors, grouped in "tranches," awaited new rate cases. There was no predisposition for a "deep think" on the perfect ARP design. Comments by the Board in its decision imply that they rejected K factors partly because they would complicate their placeholder PBR plan.[6] The K factor approach that was rejected did not use the research methodology I developed in this proceeding. The Board, in any event, left open an option for companies to file rate cases early should their capex needs be larger than the budget provided by the PBR plan.

The Board in 2008 approved a longer-term third generation PBR framework. Although the X factor was based in part on US productivity trends, this framework allowed companies to request a capital cost tracker through an Incremental Capital Module ("ICM"). At the outset of the plan, the ICM was limited to unusual projects. However, by 2013, some companies were requesting and receiving approval of ICM treatment of "business as usual" projects.

In 2012 and 2013 the Board issued a series of decisions outlining a fourth generation ARP. The diversity of companies' capex requirements discussed in the proceeding persuaded the Board to approve multiple ARP options for utilities based on their perceived capex needs. Each option would have a minimum five-year term that could start as early as 2014. One option, for distributors forecasting stable capex, would be a simplified price cap plan that

[6] Ontario Energy Board, "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors," December 20, 2006.

would not include an ICM. A second option, for those distributors which may have small capex surges, would feature a plan similar to the third generation ARP, including the ability to apply for ICMs. A third option, for distributors that anticipated a larger capex surge, allows for British-style indexing plans reliant on company cost forecasts. Contrary to the impression conveyed by Staff's comment, the evolving Ontario experience therefore has, if anything, supported the need for flexibility in addressing utility capex needs.

Q: Staff acknowledges that CMP has a high level of capital productivity but notes on page 103 of the Bench Analysis that "these results do not provide any insight into the question of whether CMP's high ranking reflects improvements in efficiency as opposed to deferrals of capital spending that should have occurred over the period." How do you respond?

A: CMP has operated under ARPs for nearly two decades, and this has doubtless strengthened its cost containment incentives. From 2002 to 2011, the Company's MFP growth was more than three times that of the upper Northeast peer group. In a capital-intensive business like power distribution, containment of capex is a key to cost management. Judicious postponement of replacement capex may be part of good capital cost management, as long as reliability continues to attain prescribed standards. The Company has met or exceeded its reliability targets.

It is also noteworthy that utilities under PBR are encouraged to achieve long-term performance gains that can be passed on to customers in the next rate case. There is a big difference between the deferral of O&M and capital spending in this respect. Suppose, first, that a utility deferred O&M maintenance (e.g. line trimming) expenses during a plan and then requested a high maintenance budget in the next rate case. The customer would in this case receive no benefit from the Company's cost cutting. In the case of deferred replacement capex, on the other hand, the customer would receive most of the benefit of low capital cost in the test year of the next case. The capex budget in the test year might be on the high side, but this would likely not be enough to offset all of the capex savings from the ARP years. Customers of CMP received the benefit of the Company's low capital cost in 2008 and will receive it again in 2014.

Q: Staff expresses concern on page 104 of the Bench Analysis that "the econometric model upon which the K factor was derived suffers from certain statistical weaknesses that render the results suspect". For example, "Statisticians employ factor analysis or principal component analysis techniques to parse a set of possible explanatory variables down to those variables that are significant. Dr. Lowry did not conduct these analyses" How do you respond?

A: I begin my response by noting that I have chosen econometric modeling rather than unit cost comparisons for my benchmarking work. Numerous explanatory variables were identified, and the benchmark reflects the estimated relative importance of these variables as cost drivers. My methodology is far more sophisticated than that which Staff employed in its benchmarking work, yet Staff believes its methodology is useful for setting the stretch factor. The capital cost benchmarking result which my model produces for CMP is also very much in line with the result of Staff's work. After all, CMP was apparently a top capital cost performer in Staff's study.

The propriety of the parameter estimation procedure is undeniably an important issue in the appraisal of an econometric study. My research was based on a custom estimation procedure that corrects for heteroskedasticity and autocorrelation. These are well known to be common problems in econometric cost research.

Factor analysis and principle component analysis are additional procedures that could in principle have been used in my research. However, these procedures are rarely used in econometric research on energy distribution cost. In its response to a data request, Staff could cite only two distribution cost studies in which these methods had been used. Only one of these was an econometric study. In that study, the authors concluded that the method had little effect on cost efficiency rankings.[7] While it is possible to imagine some constructive application of the methods Staff suggests, my study should not be dismissed because these methods were not used.

Q: Staff comments on page 105 of the Bench Analysis that "Dr. Lowry did not test for the potential multicollinearity of the explanatory variables . . . The presence of multicollinearity results in a less statistically robust model that can be more influenced by noise . . . CMP states in the 2000 ARP case with regard to econometric models developed in productivity offset analyses that 'multicollinearity also can result in increasing R^2, erroneously suggesting that the model has more predictive power than it really does' ". How do you respond?

A: Multicollinearity occurs when the explanatory variables of an econometric model are correlated. As observed in the citations provided by Staff after the technical conference, multicollinearity usually manifests itself in low t statistics and implausible parameter estimates (including switched signs) for the parameters. These citations also make the point that even a model with overall high fit may, in the presence of multicollinearity, be unable to parse the contributions to the fitted value between individual explanatory variables. The potential for multicollinearity to manifest itself in studies of utility cost is greatest when several highly

[7] Growitsch, Jamasb, and Wetzel, "Efficiency effects of observed and unobserved heterogeneity: Evidence from Norwegian electricity distribution networks", *Energy Economics* 34 (2012).

correlated output variables are needed to capture the cost impact of operating scale. The best remedy for multicollinearity is a large sample.

While multicollinearity is a potential problem, there is no evidence that it is a problem in my study. I have used a sizable sample in my econometric work for CMP. All of the parameters in my econometric model have high statistical significance and plausible values. Furthermore, power distribution is not a utility function in which a large number of output variables are needed or even available. The high R^2 of our model has not been touted as a key to its validity. We are interested for benchmarking purposes in the *combined* effect of the cost drivers, and are not especially interested in the estimates of individual model parameters.

A test for multicollinearity is not a common feature of econometric studies of distribution cost. Staff, in any event, had the opportunity to test for multicollinearity and did not do so. The extent of multicollinearity is unknown.

Q: What of Staff's concern on page 105 of the Bench Analysis about the relevance and applicability of the number of gas customers served?

A: This variable is obviously relevant in a study of power distribution cost because it is a potential source of scope economies. For combined gas and electric utilities (e.g. CMP's sister utilities NYSEG and RG&E), simultaneous growth in the number of gas and electric customers makes it possible to share certain capital costs, such as costs of trenching or general plant (e.g. office buildings).

Service to gas customers can therefore lower the reported cost of power distribution. This avenue for capital cost containment isn't available to CMP. The number of gas customers served has been a variable in several scholarly studies of power distribution cost, including the study I published in the *Energy Journal.*

Q: Staff states on page 106 of the Bench Analysis that "applying the econometric capital cost model to a sub-selected low capital cost peer group essentially converts his K factor analysis into a total factor productivity analysis but for a much smaller sample size… Such small sample sizes, combined with the potential sensitivities in the econometric model to data fluctuations due to reasons outlined above, suggests that the K Factor is a statistically unreliable value." How do you respond?

A: The New England peer group that Staff advocated in a previous ARP proceeding had only thirteen companies. The Upper Northeast peer group in my last CMP testimony had only fourteen companies. The K factor peer group for the broad Northeast has ten companies. Certainly this is an adequate sample size for K factor computations. The six-member size of the upper Northeast K factor peer group is not ideal. However, this peer group has traditionally been favored by Staff and the Upper Northeast results are assigned only a 50% weight. Should the Commission find the sample size for the upper Northeast K factor peer group unacceptable, it should at least approve the -0.36% K factor that is indicated by our research for the Broad Northeast sample.

F. Customer Growth Factor

Q. Let's turn now to the customer growth factor issue. Staff states on pages 110-11 of the Bench Analysis that "Neither Dr. Lowry nor CMP is aware that such a term has been used in any other electric utility PBR." How do you respond?

A: Staff is referring here to the inclusion of a *fixed* customer growth term in the X factor. While that is fairly unusual, it is quite common for RCI's to *explicitly* account for customer growth. As I explained in Section 2.2.2 of my supplemental testimony, this sometimes takes the form of a stand-alone customer growth term. In other cases, a utility's revenue per customer is subject to indexing, as in the new ARPs for gas distributors in Alberta.

It is also noteworthy that most decoupling true up plans that have been approved in the United States, including that for CMP in the early 1990s, have automatically escalated allowed revenue for customer growth. The Massachusetts Department of Public Utilities ("DPU") permits the revenue of gas utilities operating under decoupling to rise with customer growth, and has stated that this treatment "would ensure that revenues are more closely aligned with the number of customers – a significant driver of costs on their distribution system."[8]

Q: Staff states on page 112 of the Bench Analysis that "In reality, cost growth is driven not only by the number of customers served, but at least also by the number of kWhs sold . . . growth in number of customers served does not represent the actual trend in costs associated with the growth in output . . . customer growth over-represents the actual growth in the trend in cost." How do you respond?

A: Many econometric studies of gas and power distribution cost have shown the number of customers to be the single most important scale variable driving cost. Other potentially important cost drivers include the energy delivery volume, distribution peak demand, and the megawatt hours of voltage step-down capacity. While the delivery volume trend may be a little slower than that of customers the trend in the other variables may be more rapid. There is no reason to believe that customer growth is not a good proxy year in and year out for growth in a properly-specified index of growth in the various dimensions of operating scale. After all, the delivery volumes of CMP are forecasted to grow only a little more slowly than customers, and the total number of customers is dominated by R&C customers which have relatively peaked loads. The trend in the number of customers is therefore apt to be highly correlated with peak

[8] D.P.U. 07-50-A, 16 July 2008 p. 38.

demand and voltage reduction capacity. There is insufficient evidence in this proceeding to believe that the number of customers "over-represents" the effect of growth in operating scale on cost. In any event, basing output escalation on a more complex output formulation would require the recalculation of the MFP trend using the same output formulation, since I showed in Section 2.2.2 of my supplemental testimony that these output formulations must be consistent.

Q: How do you respond to Staff's statement on page 112 of the Bench Analysis that "Clearly, the entire distribution cost of service does not track changes in number of customers on a linear basis. Using a customer growth forecast to represent growth in cost, and thus revenue requirement, does not account for economies . . . Thus, the magnitude of the term proposed by CMP is likely to be significantly overstated"?

A: I disagree. I explained in Section 2.1.2 of my supplemental direct testimony that economies of scale are an important source of the cost efficiency growth that is captured by an MFP index. This point was acknowledged by OPA witness King at the technical conference.

Q: What of Staff's comment on pages 112-13 of the Bench Analysis that "Significant costs associated with customer growth are recovered separately through CMP's line extension charges?"

A: CMP does not charge customers for a typical service drop, but only charges those customers who require the installation of additional equipment as part of taking service (e.g., the house is set back far from the street requiring the installation of additional poles). The amounts charged are then determined on a dollar/foot basis tied to cost. The line extension revenue collected does not offset any other costs of adding new customers. In the first rate year (July 1, 2014 through June 30, 2015), CMP forecasts line extension revenue of only $2.4 million on a total distribution revenue requirement of $241 million. While the line extension revenue is nonnegligible, it must be understood that the customer pays the full capex in one year.

Q: Staff also suggests that the index logic you present to defend a customer growth term is inconsistent with your testimony in the last ARP proceeding. Is that true?

A: No. The purported "index logic inconsistency" is that in previous ARP filings no explicit account was taken of the difference between volume and customer growth in the research. But the Company was then proposing *price* cap indexes, and the appropriate MFP indexes used revenue-weighted output indexes. These placed a heavy weight on trends in delivery volumes. As Staff acknowledged in their response to ODR-154-019, trends in an MFP index using a revenue-weighted output index implicitly reflect the trends in the number of customers and use per customer. My output specifications in both cases have thus been consistent with index logic.

G. Reasonable X Factor Range

Q: Staff ultimately concludes on pages 113-14 of the Bench Analysis that "a reasonable X factor appears to be in the range of -0.60% to 1.48%." Is this a reasonable range for the Commission to consider?

A: No. I note, first of all, that Staff acknowledges that an X factor of -0.60% is in the range of reasonableness. This value would reflect a productivity differential of -0.55% and an input price differential of -0.35% using my index results for the upper Northeast peer group, a 0% K factor, a 0.30% stretch factor, and a 0% customer growth factor.

The designation of a significantly negative X factor as reasonable constitutes a notable concession on Staff's part. It also alerts the Commission to the option of using results for the Upper Northeast peer group exclusively in setting the X factor. This would maintain consistency with Staff's past peer group preferences and assist the Company with its capex financing challenge.

The details of the construction of Staff's -0.60% lower bound on X are nonetheless not entirely reasonable. Most conspicuously, it is unfair to provide no allowance whatsoever for customer growth. I have shown that a provision in the RCI to escalate allowed revenue for customer growth is fully consistent with index logic, precedent, and empirical research. Doubtless many of the utilities that receive automatic escalation for customer growth also have line extension charges. CMP has operated under price caps for years. No one has questioned its right during these years to benefit from growth in its billing determinants, and this growth is due in part to customer growth.

The proposition that the *minimum* reasonable sum of the K factor and stretch factor is positive 0.30% is also controversial. The preponderance of evidence suggests that CMP is an average or superior cost performer. There is precedent for a 0% stretch factor in Maine, and the productivity growth of the peer group already reflects the power of infrequent rate cases. Staff's critique of my econometric work is unpersuasive, and the broad Northeast sample produces a K factor of -0.36%. I therefore believe the Staff is unreasonable in not assigning at least a -0.36% lower bound on the K factor.

Q: What is your view of the high end of Staff's range?

A: This value would reflect a productivity differential of -0.22% and an input price differential of 0.95% using index results for Staff's blend of my latest results for the broad Northeast and my earlier results for the upper Northeast; a 0% K factor; a 0.75% stretch factor, and a 0% customer growth factor. I have already commented on the unreasonableness of a 0.00% customer growth adjustment. Productivity results based on Staff's blending analysis are unreasonable. The substantial 0.95% input price differential is very much out of line with the findings of my two studies. Furthermore, Staff had no input price or productivity data for the broad Northeast in the period before 2002. A stretch factor as high as 0.75% is also not supported by the evidence. Staff's acceptance of results based on blended research and a crude benchmarking study are inconsistent with the high evidentiary standard that it applies to my K factor research. An X factor as high as 1.48% would project a lack of sensitivity to the Company's need for higher capex, and encourage CMP to abandon PBR and hold frequent rate cases in coming years.

III. CHARLES KING OPA

Q: Let's turn now to the testimony of Charles King on behalf of the OPA. He states on page 36 of his testimony that "Dr. Lowry offers no explanation for his application of regional/national productivity differentials as a component of the X factor. Because regional utility productivity growth is less than national growth, the effect of Dr. Lowry's application is to suggest that the utilities have experienced negative productivity growth." Do you agree?

A: No. A productivity differential has a solid theoretical foundation. Productivity differentials have traditionally been a component of CMP ARP filings. They simply recognize that an output price index like the GDPPI reflects the substantial productivity growth of the US economy, and to this extent is an inaccurate measure of distributor input price trends.

Q: Mr. King speculates on page 36 of his testimony that "the higher productivity performance of utilities nationwide most likely results from the significant advances in gas-fired combined cycle generation technology and, to a lesser degree, wind and biofuels generation. Because CMP has no generating facilities, the productivity performance of vertically integrated utilities is irrelevant to it." Do you agree?

A: No. Mr. King appears not to have understood that I was comparing the MFP trend of

Northeast power distributors to the MFP trend of the US private business sector.

Q: Mr. King states on page 37 of his testimony that "Customer growth is one of the primary sources of productivity improvement. As such, its effect is already captured in the productivity measurement. To include it as a separate component in the X factor constitutes a double count of its effect." Is this a fair criticism?

A: No. I have already noted that the cost of a utility is a function of its operating scale. Growth in operating scale thus prompts growth in utility cost. My research acknowledges that 1% growth in the number of customers will nonetheless not produce 1% growth in cost, because of economies of scale that are captured in the base productivity growth factor. It makes no sense for the RCI to reflect the *indirect* effect of customer growth on cost but not the *direct* effect.

Q: Mr. King also states on page 37 of his testimony that "it is reasonable to expect CMP to continue to improve its productivity at a rate somewhat higher than these peer groups." How do you respond?

A: I certainly hope that CMP will continue to achieve superior productivity growth, to the benefit of its shareholders and customers. However, there is reason to think that it may not. The proposed productivity differential reflects the performance of utilities that filed rate cases infrequently. CMP's past superior productivity growth likely reduced its inefficiency, making continued rapid productivity growth more difficult. I have shown that utilities with extremely low capital cost tend to have slower productivity growth on average.

Q: Mr. King expresses concern that inflating the productivity offset by the full value of the differential between the productivity performance of CMP relative to peer groups would reduce CMP' s incentive for rapid productivity growth. He therefore recommends as a stretch factor half the difference between CMP's recent productivity

improvement and that of the peer groups. Do you agree?

A: No. His proposed approach to setting X would clearly penalize the Company for past superior productivity growth and reduce its future performance incentives. Stretch factors should for this reason be based on other considerations, such as a utility's recent operating performance. I know of no ARP, past or present, in which the stretch factor has been set using Mr. King's proposed methodology.

Q: Based on Staff's Bench Analysis or the testimony of OPA witness King, would you like to change your X factor recommendation?

A: No.

Q: Does this conclude your rebuttal testimony?

A: Yes it does.