BEFORE THE

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

BC HYDRO'S 2007 RATE DESIGN APPLICATION
BCUC Project No. 3698455

PREPARED TESTIMONY OF

JOE N. LINXWILER, JR.

ON BEHALF OF

JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE

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1. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Joe N. Linxwiler, Jr. My business address is 550 N. Bumby Avenue, Suite 110, Orlando, Florida, 32803.

Q. By whom are you employed and what is your position?

A. I am employed by the firm of Linxwiler Consulting Services, Inc., of which I am the chief executive.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of the Joint Industry Electricity Steering Committee ("JIESC"). I have been engaged by the JIESC to review the characteristics of the BC Hydro system and provide my professional opinion on the type of demand allocation method that is appropriate to use in developing the electric rates of BC Hydro. (I will also refer to BC Hydro as "BCH".)

Q. Please summarize your educational and professional background and qualifications.

A. I am a utility business analyst and rate consultant. I have been practicing in the electric utility industry for over 25 years. I formed my present firm of Linxwiler Consulting Services, Inc., in March of 2003, after some nine years as a principal in the firm of Fred Saffer & Associates, Inc., which I co-founded in January, 1994. Prior to that, I was employed by the consulting firm of R.W. Beck and Associates for approximately 17 years and, before that, by Southern Engineering Company of Georgia, another consulting firm, for approximately two years. My consulting practice is principally concentrated in the areas of rates, contracts, strategic planning, and inter-utility bulk-power and transmission arrangements. I have testified as an expert witness on these matters before a number of regulatory agencies in the United States.

I have testified before the Federal Energy Regulatory Commission ("FERC") in numerous proceedings. I have also assisted a number of publicly owned utilities in submitting comments to FERC in the rulemaking proceedings leading to Order Nos. 888 and 2000 and in other rulemaking proceedings, including the more recent rulemaking in which FERC issued Order No. 890. I have been directly involved in many proceedings before the FERC involving the wholesale rates and transmission services of many companies, including Carolina Power & Light Company, Public Service Company of Indiana, Southern California Edison, Georgia Power Company, Southern Company Services, Alabama Power Company, Florida Power & Light Company, Florida Power Corporation, Southwestern Public Service Company, and others. I first testified before FERC (or, rather, its predecessor, the Federal Power Commission) regarding electric rates in 1977. In addition to the proceedings in which I have testified, I have submitted expert affidavits is a several proceedings, and I have assisted clients involved in many

other proceedings in negotiations leading to settlements before prepared testimony was necessary. I have also been the principal drafter of, and negotiator for, many wholesale power sales agreements and coordination agreements. I have testified in state court and state regulatory proceedings and in a number of arbitration proceedings. I have also served as an arbitrator.

I attended Southern Methodist University and Georgia Institute of Technology. I received a Bachelor of Electric Engineering degree with High Honors from Georgia Tech in December, 1974, after which I completed some 32 hours of graduate course work in electrical engineering, mathematics, and systems engineering. I was a graduate research assistant at Georgia Tech in the field of mathematical systems theory, and I was an instructor in electronics at DeVry Institute of Technology in Atlanta, an accredited junior college. I am a member of the Institute of Electrical and Electronics Engineers.

Exhibit _____ (JNL-1) is a copy of my current resume, which provides further particulars on my background and experience, including a listing of proceedings in which I have submitted testimony.

Q. What is the purpose of your testimony today?

A. In this testimony, I will present and explain my findings, conclusions, and recommendations regarding the appropriate type of demand allocation factor that should be used by BC Hydro in determining its rates for electric service.

Q. Please summarize your recommendation regarding the appropriate demand allocation method for BC Hydro.

A. Based on my review of the characteristics of BC Hydro's system, I am of the opinion that the most reasonable demand allocation method for use in developing BC Hydro's

1 rates is the "4-CP" method. The "3-CP" method also would not be inappropriate for the
2 BC Hydro system. I have also concluded that the "12-CP" method is not reasonable for
3 the BC Hydro system. I will explain these methods and the basis for my
4 recommendation in the remainder of this testimony.

5 **Q. Are you sponsoring any exhibits in connection with this testimony?**

6 A. Yes, in addition to Exhibit _____ (JNL-1), which I previously described, I am submitting
7 and sponsoring exhibits identified as Exhibit _____ (JNL-2) and Exhibit _____ (JNL-3),
8 all of which were prepared by me or under my supervision and which I will describe and
9 explain herein.

10 **2. BACKGROUND**

11 **Q. Please explain what you mean by "demand allocation?"**

12 A. In order to provide the proper context for that term, I will first provide a brief overview
13 of the major steps in developing cost-based utility rates that are generally accepted in the
14 utility industries. From the broadest perspective, the are two major steps. First, the
15 amount of annual revenue that is required (and justified) from each class of customers
16 is determined. Second, rates are developed for those respective customer classes that
17 (based on expected usage) will generate the required revenue and provide appropriate
18 "price signals" to the customers. The amount of revenue required from each customer
19 class is referred to simply as the "revenue requirement." For cost-based rates, the
20 revenue requirement should reflect the costs of serving that customer class.

21 The total annual revenue requirements of most utilities (including BC Hydro)
22 consist of many so-called joint and common costs; that is, costs that the incurrence of

which cannot be directly attributed to individual customers or customer classes to the exclusion of others. This is because, for reasons of economies of scale, the vast majority of all electric utility facilities are very large facilities that serve many different customers. In particular, large generating stations and transmission lines (and substations) serve the combined requirements of many customers; indeed, they operate in tandem to serve the system as a whole. As a result, the costs of such facilities must be apportioned among, or *allocated* to, the various customer classes in some *pro rata* fashion. Hence, the respective revenue requirements that need to be recovered from the various customer classes are referred to as *allocated* revenue requirements; they represent allocated shares of the utility's total annual revenue requirement.

If rates are to be cost-based, the method or methods of allocation or apportionment should reasonably reflect the customer classes' respective contributions to the underlying need for the facilities in question. In selecting such allocation methods, costs are grouped or classified into categories of similar type. The three broadest such categories or cost classifications are (i) demand-related costs, (ii) energy related costs, and (iii) customer-related costs. Demand-related costs (or just "demand costs") are costs that have been incurred to serve the peak or maximum demands of the utilities customers. Because the peak demands of customers determines the amount of capacity or capability that the utility must have, demand-related costs are also called "capacity-related costs." Such costs are predominantly the so-called fixed costs of ownership of the utility's facilities. By contrast, energy-related costs are predominantly variable costs -- costs that directly with energy production and consumption -- such as fuel and certain types of operation and maintenance expenses. Customer-related costs are costs that

1 related to the numbers and types of customers that the utility has.

2 Sometimes it is worthwhile, for the sake of accurate cost allocation, to break a
3 utility's costs down into further subcategories and allocation them on different bases.
4 For example, production or generation-related capacity costs may be allocated in a
5 manner different from transmission-related capacity costs and distribution-related
6 capacity costs.

7 With that general background, by "demand allocation" I mean the method that
8 should be used for allocating demand-related costs of the utility in question -- BC Hydro
9 in this proceeding. More specifically, this testimony addresses the method that should
10 be used for allocating BC Hydro's production-related and transmission-related demand
11 costs.

12 **Q. What method has BC Hydro used to allocated its production and transmission**
13 **demand costs?**

14 A. BC Hydro has stated that it has used the so-called "12-CP" method, also referred to as
15 the "average of the 12 coincident peaks" and other similar monikers.

16 **Q. Please explain the 12-CP demand allocation method.**

17 A. In the 12-CP method, the total system costs are allocated to each customer class in
18 proportion to the sum of that class's contributions to the twelve monthly peak demands
19 of the total system for the year in question (which is usually called a "test year"). "CP"
20 stands for coincident peak, which denotes that the subject demands are those of the
21 subject customer classes coincident with (at the same time as), the system peak demands.
22 By contrast, non-coincident peaks are the peaks of individual customers or customer
23 classes, which often do not occur at the same time as the system peaks. (Non-coincident

1 peaks or demands are sometimes used for allocating certain types of costs.)

2 In the 12-CP method, costs are allocated in the following manner. For each
3 customer class, an allocation factor is developed. That allocation factor is a ratio or
4 fraction. The denominator of the fraction is the sum (or average) of the twelve monthly
5 system peak demands for the test year. The numerator of the fraction is the sum (or
6 average) of the subject customer class's coincident demands at the times of the system
7 peak demands. Then, the amount of demand-related costs that is allocated to the
8 customer class is simply the total demand-related costs multiplied by that ratio or
9 allocation factor. The sum of all of the allocation factors should be one (1.0) or, when
10 they are expressed as percentages, 100%, just as the sum of the allocated costs should
11 equal the total "pot" of costs being allocated.

12 For this purpose, it is appropriate to adjust the demands of the customer classes
13 to reflect (include) losses, in order to represent the demands that must be served at the
14 output of the system's generators or at the input to the transmission system, which may
15 be slightly different. This is appropriate because a load of a given size served from the
16 distribution system requires slightly more generating capacity than the same sized load
17 served from the transmission system, due to the correspondingly different losses.

18 **Q. Please briefly describe some of the other demand allocation methods that are used**
19 **by other utilities with which you are familiar.**

20 A. There are a number of methods that were widely used many years ago that were quite
21 different from the 12-CP method and similar methods. Such largely archaic methods
22 sometimes used non-coincident peak demands, just energy requirements, and sometimes
23 combinations of the two. Today, most of the demand-allocation methods in use are

similar to the 12-CP method in that they involve the use of contributions to certain system peak demands. I will only address some of the more common of these peak-contribution methods.

In the so-called "1-CP" demand-allocation method, the allocation factors are based on the single annual peak demand of the system. The denominator of the allocation factor for each customer class is the system peak demand for the year (the "system annual peak"), and the numerator is that class's contribution to that single peak demand. Similarly, the "2-CP" method reflects the customer and system demands at the times of the two greatest demands during the year. A particular variation of the 2-CP method is the summer-winter peak method, wherein the two system demands are the peak summer demand and the peak winter season demand.

In the so-called "3-CP" method, the allocation factors reflect the coincident demands of the customers at the times of the monthly system peaks during the three consecutive months that are usually the months of the highest demands throughout the year; those months are referred to as the peak months or on-peak months, while the other nine months of the year are referred to as off-peak months. The "4-CP" method similarly uses demands during four designated peak months.

3. BASIS FOR CONCLUSION

Q. What was the starting point for your review and evaluation of the appropriate type of demand allocation method that should be used for the BC Hydro system?

A. My starting point was an analysis of BC Hydro's monthly peak demands for the last seven fiscal years; that is, the years ended March 31 of each of the years 2001-2007.

1 **Q. Please explain why you have analyzed these monthly peak demands.**

2 A. As I stated previously in this testimony, the purpose of the demand allocation factor is
3 to allocated demand-related costs in proportion to a reasonable measure of cost-
4 causation. Demand-related costs are incurred in supplying or obtaining generation
5 capacity to meet expected peak loads plus reasonable reserve margins. It is thus
6 necessary and appropriate to analyze the patterns of monthly peak demands to determine
7 which monthly peak loads are of greatest significance in determining the needs for
8 generation and transmission capacity.

9 **Q. Why have you selected the years 2001-2007 to review?**

10 A. I have selected these years in order to have the most recent years available and, at the
11 same time, consider enough years that patterns and trends can be ascertained and that the
12 effects of anomalies can excluded. Considering too few years will provide too much
13 weight to unusual or insignificant years. Considering too many years can wrongly
14 include characteristics that have changed and are no longer representative. It is my
15 experience that ten years is generally too long for such a review, and that five years is
16 a just barely enough. Hence, in my view, seven years is a reasonable starting point.

17 **Q. From what source or sources did you obtain the peak-demand data that you have**
18 **reviewed?**

19 A. The data were obtained from BC Hydro in response to JIESC Information Request
20 4.17.2.

21 **Q. Please explain the nature of the demands that you are using in your analysis.**

22 A. According to the data request in response to which the data were provided, the monthly
23 peak demand values I have used represent the BCH's "native" or "domestic" loads; that

is, the values exclude off system sales and include losses on BCH's transmission and distribution systems. I believe that this is the correct type of data to consider for purposes of determining the appropriate demand-allocation method to use for BCH, and indeed any electric utility. Off-system sales should not be included for this purpose because off-system sales are not comparable to on-system loads. Off-system sales are opportunistic in nature, are affected by conditions in the broader wholesale power market, are generally not required to be cost based, and generally do not involve the same level of commitment and service priority as native loads. Furthermore, including off-system sales in this analysis could unfairly cause cost shifts among on-system customers.

Q. Have you prepared an exhibit showing the demand values provided by BC Hydro?

A. Yes. Exhibit _____ (JNL-2) contains this data and the results of a number of retailed metrics or statistics that I have calculated and reviewed as part of my evaluation.

Q. Please explain Exhibit _____ (JNL-2).

A. Exhibit _____ (JNL-2) consists of eight pages. The first two pages show the monthly peak demands of the BCH system to which I earlier referred, followed by various statistics and descriptive measures. Among other things, the exhibit shows the relative rankings of the monthly peak demands in each of the years, expressed in various ways.

Pages 3 and 4 of Exhibit _____ (JNL-2) provide graphical depictions of the monthly data, showing the relationships between the monthly peak demands in each of the years. The topmost chart on page 3 shows the data plotted in chronological order. The lower chart shows the monthly demands for the various years superimposed on a single monthly axis in order that the patterns of demands in the various years may be

more readily compared. The topmost graph on page 4 shows the same superimposed monthly load patterns, expressed and plotted as percentages of the respective annual peak demands; that is, the demands for each year have been normalized relative to the annual peak demands. The lower chart on page 4 shows the same percentages in descending order of magnitude rather than in chronological order.

Page 5 of Exhibit _____ (JNL-2) shows the calculation of two measures or metrics that may be considered useful in determining whether, and the extent to which, the 12-CP allocation method is appropriate for an electric utility.

Page 6 of Exhibit _____ (JNL-2) show various statistics and metrics pertaining to the reasonableness of a 3-CP demand-allocation method (as I described it earlier) wherein the on-peak months are November, December, and January. Page 7 is basically the same as page 6, but analyzes the appropriateness of a 3-CP allocation method with different on-peak months; namely, December-February.

Page 8 of Exhibit _____ (JNL-2) similarly shows the calculations of statistics and metrics relating to a 4-CP allocation method for the BCH system, wherein the four on-peak months are November through February.

Q. Please describe the conclusions that can be drawn from pages 1-4 of Exhibit _____ (JNL-2).

A. First, the BCH system is clearly a winter-peaking system. The peak demand each year occurs in either winter or late fall. More particularly, the annual peak demand has occurred in either December or January in every year except fiscal year 2007, when it occurred in November. This winter-peaking nature of the loads is consistent with the demands of winter space heating and lighting. Not only is the system heavily winter

1 peaking, there is a conspicuous absence of a significant summer peak period as is usually
2 present for utilities in lower latitudes. Many electric utilities in the United States have
3 two predominant peak seasons, a summer peak driven by air-conditioning loads and a
4 winter peak period driven by space-heating loads. For such utilities, the spring and fall
5 seasons are "valley" months, during with demands are lowest. By contrast, for BCH, the
6 valley extends throughout the non-peak months. This can best be seen on graphs
7 included on page 3 of Exhibit _____ (JNL-2).

8 Driven as they are by space heating loads, and in turn by cold weather which
9 ebbs and flows, BCH's annual peak is seen to occur in different months from year to
10 year, but it is always in the winter months of December through January, or in November
11 in the case of 2007. It is no surprise that, with some regularity, late November can bring
12 some very severely cold weather, sometimes followed by a temporarily milder
13 December. This was clearly the case in fiscal year 2007.

14 Again referring to the charts on page 3 of Exhibit _____ (JNL-2), it can be seen
15 that, in some years, the load pattern is not as peaked as it is in other years. This is
16 consistent with normal weather variability -- some winters are just milder than others,
17 and the resulting peak demands will be lower. On the other hand, some winters are more
18 severe than others, at least during individual months, as was the case in November 2006.

19 **Q. Please continue with your description of BCH's monthly load patterns as shown in**
20 **Exhibit _____ (JNL-2).**

21 A. I direct your attention to lines 56-67 on page 2 of Exhibit _____ (JNL-2). Here it can
22 be seen that, in every year but two (fiscal years 2001 and 2006), the *second* greatest
23 monthly peak demand occurred in either December or January. Most often, when the

annual peak occurred in January, the second greatest peak occurred in December, as *vice versa*. Only in fiscal year 2001 did the second highest demand peak demand occur in a month other than November through January, and in that year, it occurred in February. It can be seen that most often, the fourth-highest peak demand occurs in February. March most often has the fifth-greatest monthly peak demand, while October had the sixth-greatest demand in all of the seven years. March and October are, of course, transition months between summer and winter. The lowest demands in each year consistently occur in the summer months and in September, the early part of which is really just late summer.

It is quite significant that the lowest five monthly peak demands of each year all occur in the months of May-September and that those demands are generally considerably less than 80% of the annual peak. In fiscal years 2002 and 2003, the highest of the six lowest monthly peaks (that is, the seventh highest demand) in each year was only 82.06% and 83.56%, respectively. Obviously, the remaining lower months are even lower in percentages. See lines 68-79 on page 2 of Exhibit _____ (JNL-2). It can be seen from the graphs on page 3 of the exhibit that both fiscal years 2002 and 2003 had somewhat milder than usual winters, which explains the higher off-peak percentages in those years. Fiscal year 2003 was particularly mild.

The significance of off-peak demands generally being 80% or less than the annual peak (except during mild winters) is that the "gap" between those monthly peaks and the annual peak (i.e., roughly 20% or more) exceeds normal reserve planning margins by a appreciable amounts. On a system the size of BC Hydro, 5% of the peak demand is roughly 500 MW, the size of a medium-to-large thermal generating unit, and

10% of the annual peak is roughly two such units or one very large (and relatively less common) 1,000 MW unit. Beginning at about 80% of the peak demand and lower, the off-peak demands have virtually no significance in determining the need for additional generating units (with one possible exception, which I will address later in this testimony). Consider the lowest monthly peak of fiscal year 2007 (6,843 MW, occurring in August 2006). That minimum monthly peak is 3,270 MW less than the annual peak (10,113 MW), which is the rough equivalent of slightly more than six 500 MW generating units or three *very* large 1,000 MW units. It is simply not reasonable to say that BCH's summer month's demands have any appreciable effect in determining the amounts of generating capacity BCH must install or acquire.

Q. How has your analysis led you to conclude that the 12-CP allocation method is not reasonable for the BCH system?

A. The 12-CP allocation method includes the customers' demands at the times of all of the monthly peak demands on an equal basis. The method thus gives equal weight to the demands in each month, and it places an equal value on all of those monthly demands. From the characteristics of the BCH system that I have observed and described above, this is simply not reasonable. Because, as I have explained, the summer month's demands are so much lower than the winter peak demands, and the "gap" so greatly exceeds normally adequate reserve margins, the demands in those summer months simply do not have the any significance in determining capacity requirements. Those demands should not be given equal weight in the cost allocation method, as they are in the 12-CP method, because clearly not all months have the same effect of cost causation. Hence, the 12-CP demand allocation method for the BCH system does not reflect cost

1 incurrence.

2 **Q. Does the FERC use so-called load metrics or ratio tests in determining the demand-**
3 **allocation method that should be used?**

4 A. Yes, the FERC has done so in a number of cases. The ratios and other metrics that I
5 have calculated and included in Exhibit _____ (JNL-2) are, I believe, those that FERC
6 has considered from time to time. I will address some of them in more detail later in this
7 testimony. It is important to understand that, as I also will explain below, FERC itself
8 uses such ratios for guidance, and does not apply them in a rigid fashion, and rightly so
9 in my opinion.

10 **Q. Have you included the calculation of ratios or metrics used specifically to determine**
11 **whether, and the extent to which, the 12-CP allocation method is appropriate?**

12 A. Yes. On page 5 of Exhibit _____ (JNL-2), I show the calculation of two such metrics.
13 The first is the ratio of the minimum monthly demand (the lowest monthly peak
14 demand) to the annual peak demand. The higher this ratio is, the more a 12-CP method
15 is suggested; the lower it is, the less the 12-CP method is likely to be reasonable. In
16 some cases, FERC has found that the ratios above 70-71% support the 12-CP method.
17 The second such ratio is the ratio of the average of all twelve monthly peak
18 demands to the annual peak demand. As with the first ratio, the higher this ratio is, the
19 more a 12-CP method is suggested; the lower it is, the less the 12-CP method is likely
20 to be reasonable. This ratio is perhaps the most well-known of such metrics. In cases
21 where this ratio has been greater than about 81%, FERC has sometimes found that the
22 12-CP allocation factor is appropriate.
23 Here, it can be seen that, for BCH, these two ratios are slightly above the values

that FERC sometimes has considered to be indicative of the 12-CP method, absent other considerations. I emphasize *slightly*, because the differences are only a few percentage points, and these values for BCH certainly do not strongly support the 12-CP method. In cases such as this, other factors must be considered, including other characteristics of the load shape that are not captured by these two simple ratios.

Q. It appears that there are two sets of ratios shown on page 5 of Exhibit _____ (JNL-2). Please explain.

A. As I have discussed previously in this testimony, fiscal year 2003 is anomalous in that winter peak demands were lower than normal. As a result, the ratios are skewed. Looking only at the ratios, the off-peak months appear to be more significant in that year, but in fact, the peak months were just lower than usual. For this reason, it is appropriate to consider the average ratios excluding the values from 2003. For each type of ratio, I have calculated and show the maximum, minimum, and average values. By excluding 2003, it can be seen that the 12-CP allocation method is even more weakly suggested by these metrics.

Q. What conclusions should be drawn from the calculations shown on page 5 of Exhibit _____ (JNL-2)?

A. The values indicated that, in general terms, the 12-CP method *might* be suggested. However, the 12-CP is not strongly indicated. The ratios are very borderline in terms of cases in which FERC has used these metrics. In cases such as this, other factors should be considered.

Q. Has FERC defined any specific thresholds for these metrics above or below which one particular allocation or another is deemed reasonable to the exclusion of

1 **others?**

2 A. No. Although I am aware that some would attempt to apply FERC's guidance on these
3 metrics as bright-line, or knife-edge, tests, FERC itself has not done that. Indeed, FERC
4 has not adopted any standards that can be applied in that manner. Specifically, FERC
5 has stated that "the selection of a demand allocation method in a particular proceeding
6 involves the exercise of a certain amount of judgment and cannot reasonably be reduced
7 to a mathematical formula." *Lockhart Power Company*, 4 FERC ¶ 61,337 (1978).

8 **Q. Having reviewed BCH's load pattern, do you believe that it is similar to most**
9 **utilities that use, or have been directed by FERC to use, the 12-CP allocation**
10 **method?**

11 A. No. I am not familiar with *all* such utilities, but of the ones I am familiar with (which
12 are numerous), the 12-CP utilities all exhibit *two* distinct peak seasons -- winter and
13 summer. In those cases, whether the greatest peak is in the summer or the winter, the
14 other peak period is much more significant than BCH's summer peaks are relative to the
15 winter peaks. BCH has an almost imperceptible summer peak. In other words, whereas
16 the monthly load patterns of most 12-CP utilities resemble two-humped camels, BCH's
17 pattern is a one-humped camel. Because of its location, BCH has a load pattern very
18 different from most utilities that FERC deals with.

19 **Q. Earlier in this testimony, you mentioned a potential exception to your description**
20 **of the lack of significance of loads in off-peak months. Please explain that**
21 **exception.**

22 A. The exception involves routine preventative maintenance of generating facilities.
23 Generating units need to be taken out of service for preventative maintenance on a

1 regular recurring schedule, although not necessary every year. Understandably, utilities
2 schedule these maintenance outages during low-load months so that reserves remain
3 adequate during those outages, which can be a month or more in duration. If "valley"
4 load periods are not low enough and long enough, reserves can become critical during
5 those valleys, sometimes as critical as during peak months, or even more so. Thus,
6 scheduled maintenance requirements can render demands in off-peak months more
7 important and thereby justify the 12-CP demand allocation method. In such a case, the
8 utility would be said to be "maintenance saturated." "Two-humped" utilities are more
9 subject to maintenance saturation than single-peak utilities like BCH, because the valley
10 months are fewer and are not usually consecutive (because the valley months occur for
11 only one or two months in each of the fall and spring seasons).

12 **Q. Have you formed an opinion on as to whether generation maintenance**
13 **requirements justify the 12-CP method for BC Hydro?**

14 A. Yes. Given that BC Hydro's generation is predominantly hydroelectric, given the sizes
15 of its individual generating units compared to the large "gap" between on-peak and off-
16 peak loads, and given the extended length of the non-winter, off-peak period, it is clear
17 that generation maintenance requirements do not render any off-peak month more critical
18 than the winter months. Thus, generation maintenance requirements cannot rightly be
19 used here to justify the 12-CP allocation method. BC Hydro is not maintenance
20 saturated.

21 **Q. What aspects of BC Hydro's load pattern lead you to consider the 3-CP and 4-CP**
22 **demand allocation methods?**

23 A. There are several. The first is the variability of loads within the winter months. It may

be relatively easy to predict or forecast with acceptable accuracy normal temperatures and the corresponding loads, but it is very difficult to predict in advance *when* the peak will occur. We see from BCH's historical loads that the annual peak most often occurs in either January or December, so clearly both of those months should be given equal weight. This also rules out the 1-CP method in my view.

We also see that November can occasionally be the month of the annual peak, and even when it is not, the November load is usually within 10% of the annual peak. One or two large generation outages during November could easily result in inadequate reserves, so November should also be considered very important in system planning. For example, in arranging to provide capacity for the winter season, it is clear that it would be prudent to ensure that the capacity is available over the entire three-month period of November through January, at least.

Furthermore, in most years, the February loads are not a great deal lower than the November loads. Occasionally, February's load exceeds November's and even January's loads. It was therefore reasonable to consider both the 3-CP and 4-CP allocation methods.

Q. What led you not to consider a 5-CP or 6-CP method?

A. The fifth- and six-greatest monthly demands in each year are usually quite a bit lower than 90% of the annual peak. Considering their loads, they are not *as* critical as the four highest months, and are clearly transitional months. Furthermore, those months are almost always the months of March and October, months in which short-term capacity is usually readily available from other utilities in the rare event that a very large generation outage in one of those months results in inadequate remaining reserves.

(Those months are typically the valley months for utilities further south of BC Hydro.)

Q. Why do you believe that the 4-CP allocation method is the most appropriate method for the BC Hydro system?

A. In order to evaluate both the 3-CP method and the 4-CP method, I calculated and considered the metrics shown on pages 6-8 of Exhibit _____ (JNL-2). As I described earlier, pages 6 and 7 show pertinent metrics for 3-CP methods wherein the on-peak months are November through January, in the first case, and December through February, in the second. Page 8 shows the same metrics calculated for the 4-CP method, with the on-peak months defined as November through February.

The metrics I have shown on each of pages 6-8 of Exhibit _____ (JNL-2) are those that FERC has considered from time to time in connection with 3-CP and 4-CP allocation methods. See *Southwestern Public Service Company*, Opinion No. 162, 22 FERC ¶ 61,341 (1983), and *Southwestern Public Service Company*, Opinion No. 337, 49 FERC ¶ 61,296 (1989), in both of which FERC determined that the 3-CP allocation method was appropriate for the subject utility. I believe that these metrics as I have presented them are largely self-explanatory. In my view, they rule out the second 3-CP analysis (where the peak months would be December through February), because the first 3-CP analysis is a better fit. This is because, November is more significant, more often, than February. This is what I expected based on my review of the load pattern, and these metrics confirm the superiority of the November-January 3-CP method over the second alternative (even though it is slight). There is no reason to use the second 3-CP alternative. However, the metrics show that the 4-CP method is a better fit than either 3-CP method, which I believe results from the fact that it includes all of the

1 months included in the two alternative 3-CP methods.

2 **Q. Have you considered the monthly demands of individual customer classes in**
3 **reaching your conclusion regarding the appropriate demand-allocation method for**
4 **BC Hydro?**

5 A. No. I have already described the factors that I believe should be considered. I believe
6 that the total system load pattern should be considered in this determination. However,
7 in understanding the reasons which BCH's load pattern is what it is, and in evaluating
8 the effect of the inappropriate 12-CP allocation factor that BC Hydro has used, I believe
9 that it is instructive to consider differences in the load patterns of the various customer
10 classes. Frankly, if the load patterns of all of the customers were to be the same (at least
11 proportionately), changing allocation methods would have no effect.

12 **Q. Have you prepared an exhibit that shows the monthly load patterns of the major**
13 **customer groups of BC Hydro?**

14 A. Yes, Exhibit _____ (JNL-3) is a copy of a graph prepared by BC Hydro and provided
15 in response to an information request of Terasen Gas Inc. This graph shows that the
16 residential class largely drives the seasonal variability of BCH's peak demands. The
17 residential class can be seen to contribute significantly to the high winter peaks of the
18 BCH system. Other customer classes, including the industrial customers, have much
19 "flatter" loads. As a result, the 12-CP method disproportionally allocates costs to the
20 some customer classes, including the industrial customers. The 4-CP allocation method
21 (and the 3-CP method, as well) would not penalize the residential class, but would help
22 ensure that those customers pay their fair share of demand-related costs, based on cost
23 causation. The 12-CP method results in other classes of customers subsidizing the

1 residential class.

2 **Q. Does that conclude your testimony at this time?**

3 A. Yes, it does.

RESUME
OF
JOE N. LINXWILER JR.
LINXWILER CONSULTING SERVICES, INC.

Mr. Linxwiler is a utility business consultant and analyst with over 30 years of experience in electric utility finance, planning, rates, and economics. He formed Linxwiler Consulting Services, Inc., in March 2003, after nine years as a principal and officer of the firm of Fred Saffer & Associates, Inc., which he co-founded in January, 1994.

Prior his tenure with Fred Saffer & Associates, Inc., Mr Linxwiler was employed by the firm of R. W. Beck and Associates for some 17 years. He joined R. W. Beck and Associates in June, 1976, as a Senior Engineer in the Rate Department of the firm's Orlando, Florida, Regional Office, and subsequently held a number of positions with this firm. From 1982-1986, he served on the staff of the firm's Managing Partner and served as Manager of Computer Services in firm's Seattle, Washington, general office. In 1986, he returned to R. W. Beck's Orlando office to direct wholesale rate activities in the Southeast region. For the last three years of his employment there, he held the positions of Senior Client Services Director and manager of the Litigation Support and Regulatory Affairs Practice Group of that firm's Orlando, Florida, regional office.

The principal focus of Mr. Linxwiler's consulting practice has been in the areas of rates, contracts, inter-utility bulk-power arrangements, and strategic planning. He has participated in and directly supervised numerous retail and wholesale cost-of-service studies, electric rate design studies, long-range power supply studies, load forecasts, transmission system studies, financial feasibility studies, management systems studies, load management and energy conservation studies, and general business planning projects. His work in connection with electric rates and cost-of-service studies has included work on behalf of both purchasers and sellers of electric power. He also has served as a principal negotiator of power supply contracts between electric utilities and between utilities and large industrial customers.

Mr. Linxwiler attended Southern Methodist University in Dallas, Texas, and Georgia Institute of Technology in Atlanta, Georgia. He graduated from Georgia Tech in 1974, receiving a Bachelor of Electrical Engineering degree with High Honors. He subsequently completed thirty-two hours of graduate study in mathematics, electrical engineering, operations research, and mathematical systems theory at Georgia Tech. During that time, Mr. Linxwiler also held graduate research and teaching assistantships and participated in several research projects in and for the School of Electrical Engineering at Georgia Tech. He also was employed as an instructor in electronics at DeVry Institute of Technology in Atlanta, an accredited vocational junior college.

AREAS OF EXPERTISE

Cost of Service and Rate Design

Mr. Linxwiler has extensive experience in preparing cost of service and rate design studies. He has supervised and otherwise participated in the development of complete cost of service studies, cost of service reviews, and rate design studies. These studies have included the development of test-year projections, the selection and development of allocation factors, analyzing operating and financial information, the complete design of rate schedules, including terms and conditions of service. This work has included engagements for both small and large utilities and their customers. Mr. Linxwiler's engagements also have spanned work involving both retail and wholesale rates. These engagements also have involved traditional embedded-cost ratemaking applications and marginal-cost ratemaking and rate-design applications.

Electric Transmission Matters

One of Mr. Linxwiler's specialties is the transmission of electric power and, in particular, economic and regulatory matters pertaining to transmission. The transmission facilities of virtually every electric utility in the continental United States are interconnected with those of adjacent utilities, resulting in, basically, three transmission grids in the country. The reasons for these interconnections are myriad, but their existence has profound and pervasive effects on the industry – contractual arrangements between interconnected utilities are crucial to fair access to, and use of, the grids and to maintaining the reliability of the grids. Among the important characteristics of electric transmission is that, in Mr. Linxwiler's opinion, it is largely a natural monopoly in each geographical area, which also has profound implications for inter-utility agreements and the need for, and nature of, governmental regulation of those agreements. The unique, and in some cases non-intuitive, physical characteristics of electric transmission also must be recognized. Mr. Linxwiler's formal education in electrical engineering and economics and his experience in inter-utility transmission arrangements uniquely qualifies him as an expert in such matters. He first provided expert-witness testimony on such matters before the Federal Power Commission (the predecessor of the Federal Energy Regulatory Commission) in 1977. Subsequently, he as provided expert witness testimony on transmission matters in numerous regulatory proceedings and has provided other consulting services regarding transmission in many additional engagements, as evidenced by his Experience Profile (Attachment A hereto).

There are subtle, yet important differences between electric transmission and distribution, although both functions are governed by the same physical laws. Mr. Linxwiler has also extensive experience with matters pertaining to electric distribution and to the differences between transmission and distribution.

Power Supply Development

A significant amount of Mr. Linxwiler's professional experience has been in connection with existing and new regional power coordination arrangements between utilities. He has both participated in and led negotiations and studies leading to the acquisition by several municipal joint action agencies of major ownership interests in a number of nuclear and fossil-fueled generating stations. His principal areas of responsibility in these matters have been (i) the terms and conditions for interconnected operations and wholesale power exchanges, (ii) the rates for such exchanges and for wholesale "partial requirements" power, (iii) transmission wheeling arrangements, and (iv) the development of computer-based models for analyzing all of these types of arrangements. Much of his experience has involved determinations of the cost and the value of electric power and energy provided by utilities to their customers and one another. Mr. Linxwiler also has participated in the development of financing arrangements to fund major new power supply projects. These types of engagements require a broad application of utility economics, operations, and ratemaking theory.

Litigation Support/Expert Testimony

Mr. Linxwiler has served as an expert witness in numerous regulatory and judicial proceedings. Brief descriptions of the subjects of his testimony in these proceedings are provided in Exhibit A attached hereto. In addition, he has assisted in the preparation of testimony and exhibits of other witnesses in a number of proceedings. He also has participated in negotiations leading to settlements in numerous other proceedings. Virtually all of the proceedings in which he has participated, as a witness or otherwise, have involved questions relating to the cost and value of electric service.

He also has appeared as a expert witness in several proceedings in arbitration involving contractual disputes between electric utilities. These proceedings have involved issues pertaining to cost-of-service matters, rates, power sales agreements, and interchange transactions. In addition, he has served as an arbitrator in one such arbitration proceeding.

Further particulars concerning Mr. Linxwiler's educational and professional experience are provided in the aforementioned Attachment A.

Attachment A

Professional Experience of
Joe N. Linxwiler, Jr.

March 2003 to Present — Linxwiler Consulting Services, Inc.
Orlando, Florida

Joe N. Linxwiler, Jr., is a prominent utility economics and regulatory consultant and owner of Linxwiler Consulting Services, Inc. Through Linxwiler Consulting Services, Inc., Mr. Linxwiler provides consulting assistance and expertise to a broad range of publicly owned utility systems and other clients in the areas of rates and regulatory economics, power supply development, contract negotiations, and litigation support.

January 1994 to March 2003 — Fred Saffer & Associates, Inc.
Orlando, Florida

Prior to founding Linxwiler Consulting Services, Inc., Mr. Linxwiler was a senior utility specialist and Executive Consultant employed by the firm of Fred Saffer & Associates, Inc. Mr. Linxwiler was a co-founding principal and Vice President of that firm, where he was responsible for directing consulting engagements involving retail and wholesale rates, interutility contracts, regulatory matters, litigation support services, and related matters for the firm's clients throughout the United States.

1976-1993 — R. W. Beck and Associates
Orlando, Florida
Seattle, Washington

Prior to joining Fred Saffer & Associates, Mr. Linxwiler was employed by the firm of R. W. Beck and Associates for some 17 years. His experience with that firm included residencies in the firm's Orlando, Florida, and Seattle, Washington, offices. In 1976, he joined the firm's Orlando office where for several years he was engaged in many aspects of the firm's electric utility consulting practice. In 1982, he moved to the firm's General Office in Seattle for three and a half years where he served on the staff of the firm's Managing Partner and as the firm's Manager of Computer Services. During this time, Mr. Linxwiler continued to be active in work for the firm's clients. In 1986, Mr. Linxwiler returned to full-time consulting in the firm's Orlando Regional Office. In 1988, he assumed the position of Manager of Litigation Support and Regulatory Affairs in the Orlando office, in which capacity he was responsible for directing all regulated rate and litigation support engagements for the firm's clients throughout the Southeastern United States.

1974-1976 — Southern Engineering Company of Georgia
Atlanta, Georgia

Mr. Linxwiler served as a staff engineer and coordinator of computer applications for the rate and power supply departments of this engineering firm. He participated in rate studies, power supply studies, and wholesale rate proceedings for rural cooperative electric system clients throughout the Southeastern United States.

1974 School of Electrical Engineering
Georgia Institute of Technology
Atlanta, Georgia

While in graduate school, Mr. Linxwiler held graduate teaching and research assistantships and concentrated in the areas of control systems, computer science, and the application of computer modeling to electrical engineering problems. He also served as coordinator of computer use within the School of Electrical Engineering.

1974 DeVry Institute of Technology
Atlanta, Georgia

Mr. Linxwiler was employed as a part-time instructor in electronics at this accredited junior college.

Highlights of Mr. Linxwiler's consulting experience are provided below.

Alabama

In 1986 and 1987, Mr. Linxwiler directed the development of a participant billing system and budget-forecasting system for Alabama Municipal Electric Authority (AMEA), a municipal joint-action agency. He also assisted this agency in designing and establishing its general financial accounting and reporting systems. He also continues to provide management consulting services to this agency in a variety of subject areas.

In 1991, Mr. Linxwiler provided expert testimony in an Alabama state court proceeding regarding the constitutionality of state legislation establishing territorial boundaries for electric utilities in the State and related antitrust-related matters.

Periodically during 1994-1997, Mr. Linxwiler has assisted AMEA in investigating alternative rate designs. During 1997 and 1998, he served as AMEA's lead technical consultant in FERC proceedings involving the reasonableness of the open-access transmission tariff of the Southern Company and its operating subsidiaries. He filed expert witness testimony on behalf of AMEA in *Southern Company Services, Inc.*, FERC Docket Nos. ER98-1096-000, *et al.*

During 2000 and 2001, Mr. Linxwiler assisted AMEA in its participation in several FERC proceedings, mediations, and stakeholder activities concerning the establishment of one or more regional transmission organizations (RTOs) in the Southeastern United States. He was heavily involved in the stakeholder process for the proposed SeTrans RTO and, with AMEA's legal counsel, in preparing protests and comments on behalf of AMEA regarding the organic documents proposed by the SeTrans sponsors. Mr. Linxwiler was also AMEA's lead consultant in a major transmission rate case involving the Southern Company's open-access transmission tariff, *Southern Company Services, Inc.*, FERC Docket No. ER02-851-000, and was AMEA's lead negotiator in the negotiations resulting in a settlement of that proceeding.

In 2004, Mr. Linxwiler assisted AMEA in negotiating an agreement for the interconnection of AMEA's new Sylacauga Plant, a two-unit combustion turbine generating station. He continues to assist AMEA in several matters pertaining to wholesale rates and transmission arrangements.

During 2001 and 2002, Mr. Linxwiler also supervised electric rate studies for a number of AMEA's member municipalities. In 2004 and 2005, he undertook a comprehensive review of AMEA's rates for wholesale sales to its Members.

In 2005, Mr. Linxwiler was engaged by the City of Opelika, Alabama, to undertake a complete review of its retail electric rates.

California

In 1984 and 1985, Mr. Linxwiler participated in studies regarding the feasibility of forming a new power pool among various publicly owned utilities in Northern California. These studies included analyses of production cost savings and reliability issues. In 1985 and 1986, he participated in power supply and wholesale rate matters for several municipal electric systems in Southern California. He also testified as an expert witness in *Southern California Edison Company*, FERC Docket No. ER84-75-000. In 1987, he performed a review of resource and strategic planning methods for Los Angeles Department of Water and Power.

Beginning in early 1998, Mr. Linxwiler has been assisting the California Independent System Operator in determining appropriate rates and charges for "must-run" generation necessary to support reliability of the California transmission grid. He filed expert witness testimony on behalf of the ISO in *San Diego Gas & Electric Company*, FERC Docket Nos. ER98-496-000 and ER98-2160-000. He participated in negotiations leading to the settlements in these and a number of other FERC proceedings relating to must-run generation for transmission system support.

In late 2004 and early 2005, Mr. Linxwiler was retained by Truckee Donner Public Utility District to assist it in a transmission rate proceeding, *Sierra Pacific Power Resources Operating Companies*, FERC Docket No. ER05-14-000. Mr. Linxwiler analyzed the claimed transmission costs of Sierra Pacific Power Company, assisted the client's counsel in preparing a formal protest of the proposed transmission rate, and assisted in negotiations resulting in a settlement (with a rate significantly below the company's proposed rate).

Florida

From 1976 through 1982, Mr. Linxwiler participated in regulatory proceedings and negotiations concerning wholesale rates, interconnection agreements, wheeling arrangements, and other matters for over 20 municipally owned electric systems throughout Florida. He testified as an expert witness on behalf of wholesale customers in *Florida Power & Light Company*, FERC Docket No. ER77-175, and *Florida Power & Light Company*, FERC Docket No. ER78-19. He also led settlement negotiations in several other proceedings.

Mr. Linxwiler also has supervised load forecasting and load research projects for several of these clients. Two of these projects included comprehensive consumer surveys.

In 1982 through 1984, Mr. Linxwiler participated in power supply planning studies for the Florida Municipal Power Agency, a joint-action agency comprised of most of the municipal electric systems in the state. He was involved in analyses and negotiations leading to the settlement of a large anti-trust suit involving a number of Florida utilities.

During 1992-1996, Mr. Linxwiler directed consulting activities in several major Florida Power Corporation

wholesale rate proceedings on behalf of Florida Municipal Power Agency (FMPA) and was a lead negotiator in negotiations that led to settlements in these proceedings. He has continued to serve as a consultant and as an expert witness for FMPA in several wholesale rate proceedings involving Florida investor-owned utilities. These proceedings involve full- and partial-requirements rates and terms and conditions, interchange agreements, and transmission wheeling services. He has filed expert affidavits and testimony in *Florida Municipal Power Agency v. Florida Power & Light Company*, FERC Docket No. TX94-3-000 (involving one of the first applications for transmission service pursuant to the Energy Policy Act of 1992) and *Florida Power & Light Company*, FERC Docket Nos. ER93-465-000, *et al*. In mid-1994, he testified before the Florida Public Service Commission, in FPSC Docket No. 940345, regarding reserve planning and operating practices and the effects of non-firm sales on such practices.

Since 1996, Mr. Linxwiler has been the lead technical consultant for FMPA in FERC proceedings involving the open-access transmission tariffs of Florida Power Corporation, Florida Power & Light Company, and Tampa Electric Company. He has also assisted FMPA is formula rate audits of Florida Power & Light Company and in a large, complex antitrust suit against Florida Power & Light (which was settled just prior to trial). He also submitted expert witness testimony in *Florida Power & Light Company*, FERC Docket Nos. ER99-2770-000, *et al.* He subsequently assisted in negotiating settlements in FERC Docket Nos. ER93-465-000, *et al.*, and ER99-2770-000, *et al.*

During 2000 and 2001, Mr. Linxwiler assisted FMPA in FERC proceedings involving the merger of Florida Power Corporation and Carolina Power & Light Company and in negotiating a settlement resolving FMPA's concerns over the anticompetitive effects of the merger. He also assisted FMPA in FERC proceedings concerning the proposed, but later withdrawn, merger of Florida Power & Light Company and Entergy. He provided expert affidavits on behalf of FMPA and Seminole Electric Cooperative, Inc., in *FPL Group, Inc. and Entergy Corporation*, FERC Docket No. EC01-33-000.

Since late 1999, Mr. Linxwiler has been assisting FMPA in the formation of a regional transmission organization in Peninsular Florida pursuant for FERC Order No. 2000. In that regard, he has been an active participant in stakeholder working groups formed for that purpose and has assisted FMPA's attorneys in preparing protests, pleadings, other filings before the FERC. He submitted an affidavit regarding transmission pricing in *Florida Power & Light Company and Tampa Electric Company*, FERC Docket No. ER01-2205-000. In 2002, Mr. Linxwiler also assisted FMPA in project to assist several of its transmission-owning members in preparing to meet the likely regulatory requirements for obtaining compensation for their transmission facilities from the proposed Grid Florida RTO.

In 2003 and 2004, Mr. Linxwiler assisted FMPA in analyzing and resolving pricing disputes under a major wholesale power supply agreement. He also assists FMPA's staff in audits of costs under several joint-ownership agreements.

In 2004 and 2005, Mr. Linxwiler continued to assist FMPA in matters pertaining to transmission service from Florida Power & Light Company remaining at issue in *Florida Power & Light Company*, FERC Docket Nos. ER93-465-000, *et al.* He submitted several expert affidavits regarding FP&L's transmission facilities and FMPA's use of transmission service. In January 2006, Mr. Linxwiler submitted an expert affidavit accompanying FMPA's reply comments in FERC's Notice of Inquiry regarding transmission service in Docket No. RM05-26.

Georgia

Since 1976, Mr. Linxwiler has participated in financing studies, strategic planning activities, power supply studies, and wholesale rate and interconnection negotiations for the Municipal Electric Authority of Georgia, comprised of 47 municipal electric systems. He submitted expert witness testimony in *Georgia Power Company*, FPC Docket No. ER76-587, *Georgia Power Company*, FERC Docket No. ER78-166, *Georgia Power Company*, FERC Docket No. ER79-88, and participated in analyses and negotiations leading to settlements in several other proceedings. In 1989, Mr. Linxwiler directed a study of a proposed new pooling and power coordination arrangement among Georgia Power Company, MEAG, and other utilities in Georgia. He also testified in *Southern Company Services, Inc.*, FERC Docket No. ER89-48-000, regarding the Southern Company pool's Intercompany Interchange Contract. He has also supervised the development of several computerized budgeting, financial planning, and management information systems for this agency. In recent years, Mr. Linxwiler has assisted this agency in general strategic planning, in the development of a new power coordination and wholesale power arrangement, and in a variety of other matters involving retail and wholesale rates and regulation.

During 1996, Mr. Linxwiler served as an expert witness for the City of Calhoun, Georgia, in a state court proceeding involving disputes between Calhoun and the Municipal Electric Authority of Georgia. During 1997 and 1998, he was also engaged by the City of LaGrange, Georgia, to assist it in a similar proceeding, which was settled just prior to trial.

Indiana

From 1979 through 1982, Mr. Linxwiler supervised a wide range of consulting services for Wabash Valley Power Association (WVPA), an Indianapolis-based G&T cooperative comprised of 24 REMC distribution systems. In addition to providing general consulting to WVPA's management, Mr. Linxwiler has supervised the development of management information systems, provided general data processing consulting, and supervised an extensive on-going load forecasting and load research project which included consumer surveys, and end-use and econometric forecasting. He served as project manager in the design and acquisition of a central control system for load management and generation scheduling. In 1995, Mr. Linxwiler was engaged to develop new rates and pricing strategies for WVPA.

In 1999, Mr. Linxwiler was engaged by the Indiana Municipal Power Agency to assist in the resolution of disputes under certain agreements between IMPA and PSI Energy. He provided expert witness testimony in an arbitration proceeding regarding appropriate cost allocation principles, and has continued to assist IMPA in related matters. In 2000, Mr. Linxwiler testified as an expert witness on behalf of IMPA, WVPA, and certain other wholesale purchasers in a FERC rate proceeding involving PSI Energy; he also participated in settlement negotiations leading to a settlement in this proceeding.

Kentucky

Since 2001, Mr. Linxwiler has been providing technical assistance to legal counsel for municipal wholesale customers of Kentucky Utilities in a long-standing dispute over excessive fuel-adjustment clause charges. A partial settlement has been achieved in that dispute, but some issues remained in negotiations in early 2005.

Louisiana

In 1984 and 1985, Mr. Linxwiler assisted in studies and analyses for the City of New Orleans regarding the possible acquisition by the City of the properties of New Orleans Public Service Company. Mr. Linxwiler provided special consulting regarding pool transactions between New Orleans Public Service Company and other subsidiaries of Middle South Utilities (now known as "Entergy").

Massachusetts

During 1982 and 1983, Mr. Linxwiler assisted in the preparation of two studies of energy conservation and load management programs for municipal electric systems in Massachusetts. In 1989, he testified as an expert witness, on behalf of the Massachusetts Bay Transportation Authority, before the Massachusetts Department of Public Utilities regarding a retail rate increase requested by Boston Edison Company.

Missouri

During 2004, Mr. Linxwiler assisted Independence Power & Light, Independence, Missouri, in protesting and reaching a settlement involving a proposed, significant increase in the rates for IPL's unit-power purchase from the Montrose Generating Station of Kansas City Power & Light Company. Mr. Linxwiler analyzed KCPL's proffered cost support, identified a number of fallacies and other issues, and assisted IPL in negotiating a very favorable settlement of the proceeding (*Kansas City Power & Light Company*, FERC Docket No. ER03-997-000).

New Hampshire

In 1991 and 1992, Mr. Linxwiler served as a member of a team of senior business and technical consultants engaged to develop and implement a reorganization plan to resolve the bankruptcy of New Hampshire Electric Cooperative, Inc. Mr. Linxwiler, along with the cooperative's legal counsel, was responsible for negotiating settlements of several disputes between the cooperative and Public Service Company of New Hampshire and for negotiating a new power supply program that served as the cornerstone for the cooperative's reorganization plan, which was approved by the Bankruptcy Court in March 1992. Mr. Linxwiler was a lead negotiator in working out a consensual reorganization plan for the cooperative with Public Service Company of New Hampshire, Northeast Utilities, New England Power Company, the State of New Hampshire, and the Rural Electrification Administration. He was also responsible for overseeing the studies necessary for demonstrating to the Court the financial feasibility of the reorganization plan.

New York

In 1986 and 1987, Mr. Linxwiler served as project manager for feasibility studies concerning public power acquisition of Long Island Lighting Company. The firm's clients in this work were the County of Suffolk, New York, and the firm of Smith Barney Harris Upham & Company. These studies were based on a proposed acquisition of LILCO's common stock and involved a broad range of financial rate making and accounting and legislative and tax-related questions, as well as power supply and system reliability considerations.

North Carolina

Over several years, Mr. Linxwiler participated in wholesale rate proceedings and negotiations and power supply studies for virtually all of the municipally owned electric systems in North Carolina. He testified as an expert witness in *Carolina Power & Light Company*, FPC Docket No. ER76-495, *Carolina Power & Light Company*, FERC Docket No. ER77-485, and *Virginia Electric and Power Company*, FERC Docket No. ER78-522.

Mr. Linxwiler participated in negotiations and studies for two major joint action agencies, North Carolina Municipal Power Agency No. 1 and North Carolina Eastern Municipal Power Agency, resulting in a billion dollar, joint-ownership arrangement with two major investor-owned utilities in the State. He played a key role in the negotiation and development of the rate, interconnection, and interchange aspects of these arrangements.

Mr. Linxwiler also participated in the development and implementation of management information and reporting systems for these agencies. He also has supervised load forecasting, load research, and load management projects for the North Carolina power agencies. Additionally, he supervised the design and acquisition of a large telemetry and control system for dynamic scheduling, electronically transferring loads of a number of cities from one control area to another.

In 1987 and 1988, Mr. Linxwiler served as an expert witness on behalf of North Carolina Municipal Power Agency No. 1 and Piedmont Municipal Power Agency in two arbitration proceedings with Duke Power Company. Also in 1988, Mr. Linxwiler submitted testimony before FERC on behalf of North Carolina Eastern Municipal Power Agency in *North Carolina Eastern Municipal Power Agency v. Carolina Power & Light Company*, FERC Docket No. EL88-27-000. In 1990, Mr. Linxwiler testified in an arbitration proceeding involving NCEMPA and CP&L.

From 1989 through 1993, Mr. Linxwiler also provided consulting services to these agencies in a variety of matters related to strategic planning, power supply economics, and wholesale rates.

Ohio

In 2005, Mr. Linxwiler was retained by Green Mountain Energy Company to assist it in FERC proceedings regarding “Seams Elimination Charge Assignments” (“SECA” charges) assessed to it by the Midwest Independent System Operator in connection with the elimination of transmission rate “pancaking” between the MISO and PJM. transmission systems.

South Carolina

For several years, Mr. Linxwiler supervised all wholesale and retail rate studies, negotiations, and related activities for the South Carolina Public Service Authority, a state-established electric utility, generating and distributing electric power at wholesale and retail throughout much of South Carolina. In the early 1980's, he was deeply involved on behalf of the Authority in negotiations leading to service to a major new industrial customer, a 300-MW aluminum reduction plant. He also was a lead negotiator in negotiations for a new power supply arrangement between the Authority and a large G&T cooperative. He also designed a long-range revenue requirements and financial planning model for the Authority. In 1990, he assisted the Authority in negotiating a major extension and amendment to its contract with the aforementioned aluminum facility and served as an expert witness in litigation between the Authority and the U. S. Army Corps of Engineers regarding

the Authority's hydroelectric facilities. Mr. Linxwiler continues to provide consulting services to this client on a number of areas, including general strategic planning, wholesale and retail rates, interutility coordination, and litigation support.

In 1992, Mr. Linxwiler led a comprehensive strategic planning effort to review the goals and objectives of the Authority's pricing and marketing efforts. In 1993, Mr. Linxwiler supervised a comprehensive rate study wherein all the Authority's retail rates and rate schedules were restructured and updated, consistent with the results of the planning effort the year before.

In 1994-1996, Mr, Linxwiler assisted the Authority in developing its open-access wholesale transmission tariff and in other matters relating to FERC Order Nos. 888 and 889. In 1999 and again in 2002, Mr. Linxwiler also assisted the Authority in negotiating of major new power supply arrangements for Saluda River Electric Cooperative, Inc., and Central Electric Power Cooperative, Inc. In recent years, Mr. Linxwiler has also assisted the Authority in a number of negotiations related to wholesale power arrangements.

In 2002 and 2003, Mr. Linxwiler assisted the Authority in successfully defending its retail rates in a class action lawsuit brought by certain disgruntled customers. In 2005, Mr. Linxwiler assisted the Authority in developing a special economic "load retention rider" to provide certain incentive for large industrial customers in light of rapidly rising fuel costs.

From 1979 through 1993, Mr. Linxwiler also participated in power supply, interconnection, and rate studies, litigation, and negotiations for Piedmont Municipal Power Agency.

In 2005, Mr. Linxwiler was retained my the City of Union, South Carolina, to assist it in matters involving the City's wholesale power supply costs.

Texas

In July 1992, Mr. Linxwiler served as the Senior Consultant on the consulting team engaged by the Public Service Board of the City of El Paso, Texas, to investigate (i) the feasibility of acquiring the properties of El Paso Electric Company, which is currently in Chapter 11 bankruptcy, and (ii) other measures or actions that the City of El Paso could take to protect the interest of its citizens in matters involving El Paso Electric bankruptcy.

In 2005, Mr. Linxwiler was engaged by Golden Spread Electric Cooperative to assist in two major wholesale rate proceedings involving Southwestern Public Service Company on issues pertaining to cost allocation.

Vermont

During 2000 and 2001, Mr. Linxwiler provided consulting services to a number of municipal electric utilities that purchase power from the Vermont Yankee Nuclear Power Corporation in FERC proceedings involving the proposed sale of the Vermont Yankee Nuclear Power Station to AmerGen.

Virginia

From 1976-1981, Mr. Linxwiler assisted in a number of wholesale rate proceedings and power supply contract negotiations for a number of Virginia municipal electric systems. He testified as an expert witness in *Virginia Electric & Power Company*, FERC Docket No. ER78-522-000.

During 1996-1997, he served as lead consultant for Virginia Municipal Electric Association No. 1 (VMEA) in FERC proceedings involving the open-access transmission tariff of Virginia Electric & Power Company. He continues to assist VMEA and its attorneys in wholesale rate and transmission matters. During 1999, Mr. Linxwiler also direct the design and development of a new computer software system for member billing for VMEA.

Utah

In 1984 and 1985, Mr. Linxwiler assisted in the preparation of power supply plans for municipal wholesale customers of Utah Power & Light Company and was responsible for projections of UP&L's power costs.

The table beginning on the next page lists the proceedings in which Mr. Linxwiler has presented expert witness testimony and the subject matters of that testimony.

Expert Witness Testimony by
Joe N. Linxwiler, Jr.

Proceeding	Subject Matter
Carolina Power & Light Company FPC Docket No. ER76-495	Average Rate Base Depreciation Expenses Income Taxes Allocation Factors Deferred Income Taxes
Georgia Power Company FPC Docket No. ER76-587	Functionalizations Allocation Income Taxes
Florida Power & Light Company FERC Docket No. ER77-175	Transmission Wheeling Transmission Losses Levelized Fixed Charge Rate Functionalizations Allocation Factors
Carolina Power & Light Company FERC Docket No. ER77-485	Depreciation Expense Interest Expense Deferred Income Taxes Investment Tax Credit Power Factor Adjustments
Georgia Power Company FERC Docket No. ER78-166	Time Weighting Plant Investment Demand Allocation Factors Functionalization of Hydroelectric Facilities Preference Power Allocation Capacity and Energy Losses Interchange Power Tariff Terms and Conditions
Florida Power & Light Company FERC Docket No. ER78-19	Functionalizations Demand Allocations Losses Income Taxes Rate Design Terms and Conditions
Virginia Electric & Power Company FERC Docket No. ER78-522	Transmission Losses Hydroelectric Capacity Functionalizations Income Taxes
Georgia Power Company FERC Docket No. ER79-88	Rate Design Terms and Conditions Partial Requirements Service Interchange Services Pricing
Southern California Edison Company FERC Docket No. ER84-75-000	Fuel Stocks Energy Supply Reliability
North Carolina Eastern Municipal Power Agency v. Carolina Power & Light Company FERC Docket No. EL88-27-000	Terms and Conditions of Interconnection Bulk Power Market Competition
Re: Boston Edison Company Massachusetts Department of Public Utilities Case No. 89-100	Marginal Cost Pricing & Rate Demand Allocation Method

Proceeding	Subject Matter
Southern Services, Inc. FERC Docket No. ER89-48-000	Pool Capacity Equalization Capacity Cost Allocations
Appeal of South Carolina Public Service Authority, Contract No. DACW60-77-C-0005 U. S. Army, Engineer Board of Contract Appeals Case No. ENG BCA No. 5564	Power System Operations Power System Economics Value of Hydroelectric Facilities and Hydroelectric Capacity
Dixie Electric Cooperative, et al., v. The Citizens of the State of Alabama, et al. State of Alabama, Circuit Court of Montgomery County, Case No. CV-86-878-G	Territorial Assignments Fair Value of Utility Property Fair Compensation for Condemnation General Utility Economic Matters
Florida Power & Light Company FERC Docket Nos. ER93-465-000, *et al.*	Terms and Conditions for Interchange Service Reserve Margin Criteria Transmission Service Pricing Pricing of Partial Requirements Service Fuel Adjustment Clause
In Re: Generic Investigation Into the Planning Practices and Operating Reserves of Peninsular Florida Generating Electric Utilities Florida Public Service Commission Docket No. 940345-EU	Reserve Margin and Reliability Criteria Provision of Interruptible Service Energy Broker
City of Calhoun v. Municipal Electric Authority of Georgia, State of Georgia, Superior Court of Gordon County, Civil Action File No. 28934	Fair and Non-Discriminatory Rates Interpretation of Contract Terms Damage Estimates
San Diego Gas & Electric Company FERC Docket Nos. ER98-496-000 and ER98-2160-000	Cost-Based Rates for Must-Run Generation Service, Formula Rates, Fixed/Variable O&M Allocations
Southern Company Services, Inc. FERC Docket Nos. ER98-1096-000, *et al.*	Cost-Based Rates for Ancillary Services under Open Access Transmission Tariff
Florida Power & Light Company FERC Docket Nos. ER99-2770-000, *et al.*	Formula Rates, Generation Step-up Facilities, Ratemaking Treatments of Accruals for Future Liabilities, Various Cost Accounting Matters
PSI Energy, Inc. FERC Docket No. ER00-188-000	Purchased Power Expenses, Off-System Sales Revenues Reserve Margins
Re: Review of GridFlorida Regional Transmission Organization (RTO) Proposal, Florida Public Service Commission Docket No. 020233-EI	A variety of matters relating to transmission service and transmission pricing.
Golden Spread Electric Cooperative, Inc., et al. v. Southwestern Public Service Company, FERC Docket Nos. EL05-19-002 and ER05-168-001	Demand cost allocation method for partial-requirements wholesale rate.
Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER05-06-001, et al.	Recovery of "Seams Elimination Charge Assignments" related to the elimination of transmission rate "pancaking."

In addition, Mr. Linxwiler has submitted expert-witness affidavits in a number of other regulatory proceedings, and he has served as an expert witness in several arbitration proceedings involving contract disputes between utilities. He also has served as an arbitrator.

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

1. Basic Review of Historical Monthly Peaks

Line	Description	2001	2002	2003	2004	2005	2006	2007
	Monthly Firm Peak Demands							
1	April	6,865,000	7,133,000	7,087,000	7,308,000	7,031,000	7,530,000	7,357,000
2	May	6,545,000	6,522,000	6,701,000	6,537,000	6,618,000	6,640,000	6,902,000
3	June	6,400,000	6,281,000	6,487,000	6,546,000	6,729,000	6,782,000	7,220,000
4	July	6,508,000	6,234,000	6,571,000	6,696,000	6,960,000	7,007,000	7,304,000
5	August	6,529,000	6,387,000	6,585,000	6,649,000	6,984,000	7,039,000	6,843,000
6	September	6,490,000	6,452,000	6,662,000	6,577,000	6,748,000	7,095,000	7,013,000
7	October	7,402,000	7,553,000	7,850,000	7,741,000	7,686,000	7,723,000	8,327,000
8	November	8,241,000	8,238,000	8,196,000	8,643,000	8,747,000	9,128,000	10,113,000
9	December	8,995,000	8,692,000	8,481,000	8,883,000	8,947,000	9,317,000	9,315,000
10	January	8,154,000	8,398,000	8,291,000	9,619,000	9,437,000	9,016,000	9,567,000
11	February	8,280,000	7,929,000	8,157,000	8,638,000	8,453,000	8,789,000	8,778,000
12	March	7,832,000	8,037,000	8,044,000	8,094,000	7,839,000	8,411,000	8,613,000
13	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
14	Minimum Monthly Peak	6,400,000	6,234,000	6,487,000	6,537,000	6,618,000	6,640,000	6,843,000
15	Average of Monthly Peaks	7,353,417	7,321,333	7,426,000	7,660,917	7,681,583	7,873,083	8,112,667
16	Month of Annual Peak	December	December	December	January	January	December	November
17	Month of Minimum Monthly Peak	June	July	June	May	May	May	August
	Monthly Demands as Percents of Annual Peak							
18	April	76.32%	82.06%	83.56%	75.97%	74.50%	80.82%	72.75%
19	May	72.76%	75.03%	79.01%	67.96%	70.13%	71.27%	68.25%
20	June	71.15%	72.26%	76.49%	68.05%	71.30%	72.79%	71.39%
21	July	72.35%	71.72%	77.48%	69.61%	73.75%	75.21%	72.22%
22	August	72.58%	73.48%	77.64%	69.12%	74.01%	75.55%	67.67%
23	September	72.15%	74.23%	78.55%	68.38%	71.51%	76.15%	69.35%
24	October	82.29%	86.90%	92.56%	80.48%	81.45%	82.89%	82.34%
25	November	91.62%	94.78%	96.64%	89.85%	92.69%	97.97%	100.00%
26	December	100.00%	100.00%	100.00%	92.35%	94.81%	100.00%	92.11%
27	January	90.65%	96.62%	97.76%	100.00%	100.00%	96.77%	94.60%
28	February	92.05%	91.22%	96.18%	89.80%	89.57%	94.33%	86.80%
29	March	87.07%	92.46%	94.85%	84.15%	83.07%	90.28%	85.17%
30	Minimum Monthly Peak	71.15%	71.72%	76.49%	67.96%	70.13%	71.27%	67.67%
31	Average of Monthly Peaks	81.75%	84.23%	87.56%	79.64%	81.40%	84.50%	80.22%
	Monthly Demands In Ranked Descending Order							
32	Greatest (Annual Peak)	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
33	2-nd Greatest	8,280,000	8,398,000	8,291,000	8,883,000	8,947,000	9,128,000	9,567,000
34	3-nd Greatest	8,241,000	8,238,000	8,196,000	8,643,000	8,747,000	9,016,000	9,315,000
35	4-th Greatest	8,154,000	8,037,000	8,157,000	8,638,000	8,453,000	8,789,000	8,778,000
36	5-th Greatest	7,832,000	7,929,000	8,044,000	8,094,000	7,839,000	8,411,000	8,613,000
37	6-th Greatest	7,402,000	7,553,000	7,850,000	7,741,000	7,686,000	7,723,000	8,327,000
38	7-th Greatest	6,865,000	7,133,000	7,087,000	7,308,000	7,031,000	7,530,000	7,357,000
39	8-th Greatest	6,545,000	6,522,000	6,701,000	6,696,000	6,984,000	7,095,000	7,304,000
40	9-th Greatest	6,529,000	6,452,000	6,662,000	6,649,000	6,960,000	7,039,000	7,220,000
41	10-th Greatest	6,508,000	6,387,000	6,585,000	6,577,000	6,748,000	7,007,000	7,013,000
42	11-th Greatest	6,490,000	6,281,000	6,571,000	6,546,000	6,729,000	6,782,000	6,902,000
43	12-th Greatest	6,400,000	6,234,000	6,487,000	6,537,000	6,618,000	6,640,000	6,843,000

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

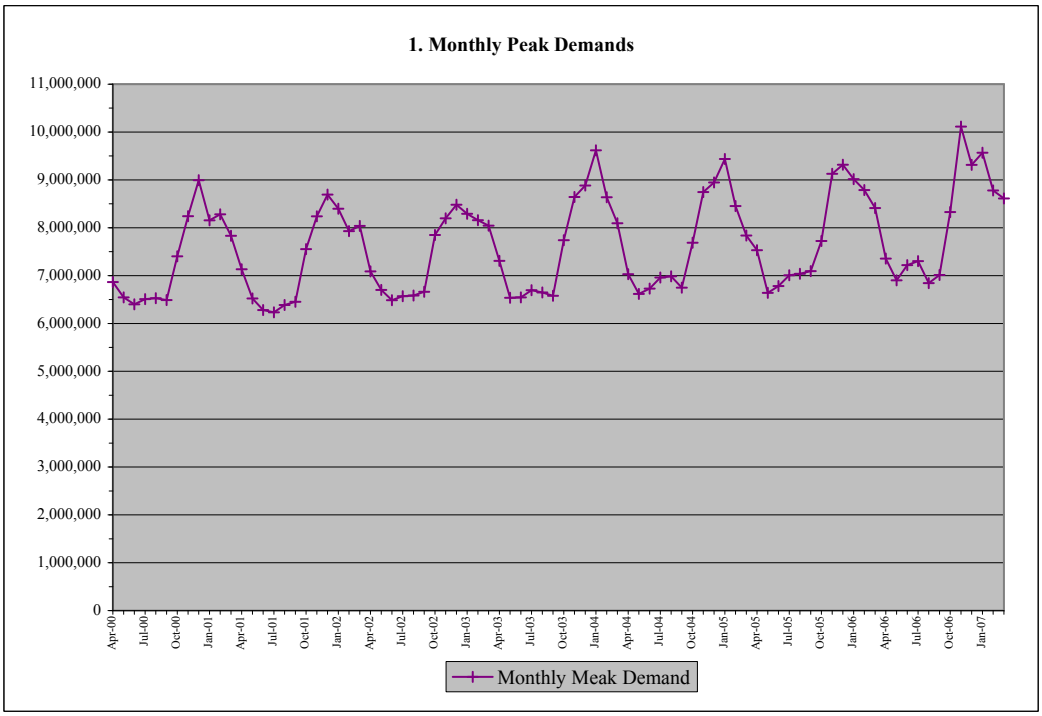
1. Basic Review of Historical Monthly Peaks

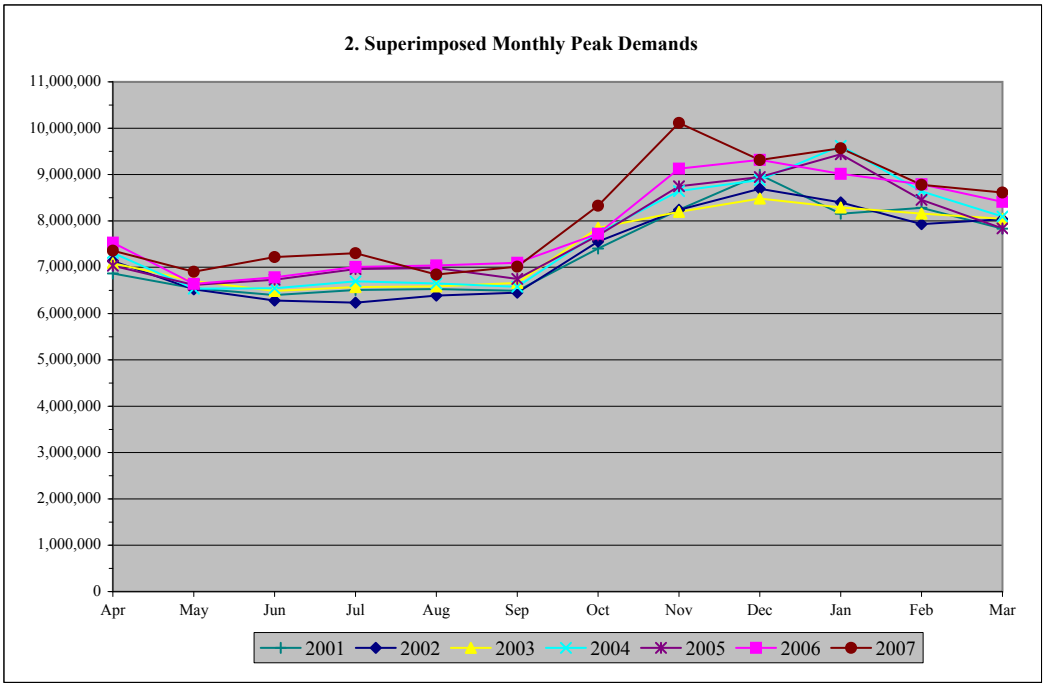
Line	Description	2001	2002	2003	2004	2005	2006	2007
	Month Numbers of Ranked Peaks							
44	Greatest (Annual Peak)	9	9	9	10	10	9	8
45	2-nd Greatest	11	10	10	9	9	8	10
46	3-nd Greatest	8	8	8	8	8	10	9
47	4-th Greatest	10	12	11	11	11	11	11
48	5-th Greatest	12	11	12	12	12	12	12
49	6-th Greatest	7	7	7	7	7	7	7
50	7-th Greatest	1	1	1	1	1	1	1
51	8-th Greatest	2	2	2	4	5	6	4
52	9-th Greatest	5	6	6	5	4	5	3
53	10-th Greatest	4	5	5	6	6	4	6
54	11-th Greatest	6	3	4	3	3	3	2
55	12-th Greatest	3	4	3	2	2	2	5
	Month Names of Ranked Peaks							
56	Greatest (Annual Peak)	December	December	December	January	January	December	November
57	2-nd Greatest	February	January	January	December	December	November	January
58	3-nd Greatest	November	November	November	November	November	January	December
59	4-th Greatest	January	March	February	February	February	February	February
60	5-th Greatest	March	February	March	March	March	March	March
61	6-th Greatest	October	October	October	October	October	October	October
62	7-th Greatest	April	April	April	April	April	April	April
63	8-th Greatest	May	May	May	July	August	September	July
64	9-th Greatest	August	September	September	August	July	August	June
65	10-th Greatest	July	August	August	September	September	July	September
66	11-th Greatest	September	June	July	June	June	June	May
67	12-th Greatest	June	July	June	May	May	May	August
	Monthly Demands In Ranked Descending Order							
68	Greatest (Annual Peak)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
69	2-nd Greatest	92.05%	96.62%	97.76%	92.35%	94.81%	97.97%	94.60%
70	3-nd Greatest	91.62%	94.78%	96.64%	89.85%	92.69%	96.77%	92.11%
71	4-th Greatest	90.65%	92.46%	96.18%	89.80%	89.57%	94.33%	86.80%
72	5-th Greatest	87.07%	91.22%	94.85%	84.15%	83.07%	90.28%	85.17%
73	6-th Greatest	82.29%	86.90%	92.56%	80.48%	81.45%	82.89%	82.34%
74	7-th Greatest	76.32%	82.06%	83.56%	75.97%	74.50%	80.82%	72.75%
75	8-th Greatest	72.76%	75.03%	79.01%	69.61%	74.01%	76.15%	72.22%
76	9-th Greatest	72.58%	74.23%	78.55%	69.12%	73.75%	75.55%	71.39%
77	10-th Greatest	72.35%	73.48%	77.64%	68.38%	71.51%	75.21%	69.35%
78	11-th Greatest	72.15%	72.26%	77.48%	68.05%	71.30%	72.79%	68.25%
79	12-th Greatest	71.15%	71.72%	76.49%	67.96%	70.13%	71.27%	67.67%
	Ranks of Months							
80	April	6	6	6	6	6	6	6
81	May	5	5	5	1	1	1	2
82	June	1	2	1	2	2	2	4
83	July	3	1	2	5	4	3	5
84	August	4	3	3	4	5	4	1
85	September	2	4	4	3	3	5	3
86	October	7	7	7	7	7	7	7
87	November	10	10	10	10	10	11	12
88	December	12	12	12	11	11	12	10
89	January	9	11	11	12	12	10	11
90	February	11	8	9	9	9	9	9
91	March	8	9	8	8	8	8	8

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

1. Basic Review of Historical Monthly Peaks (Continued)

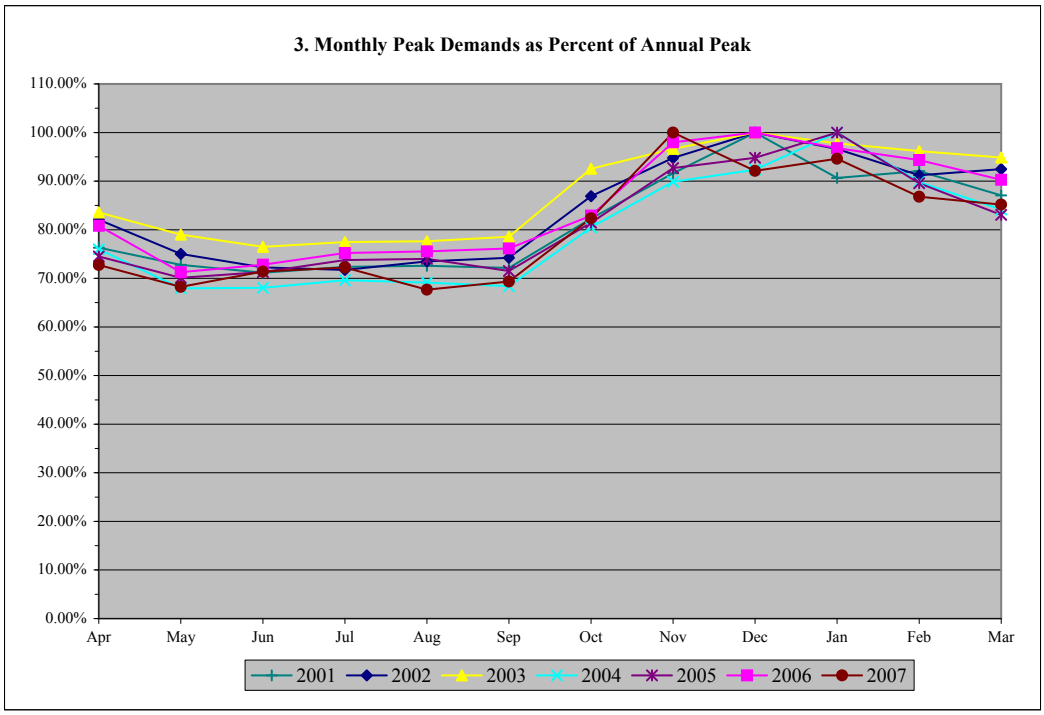


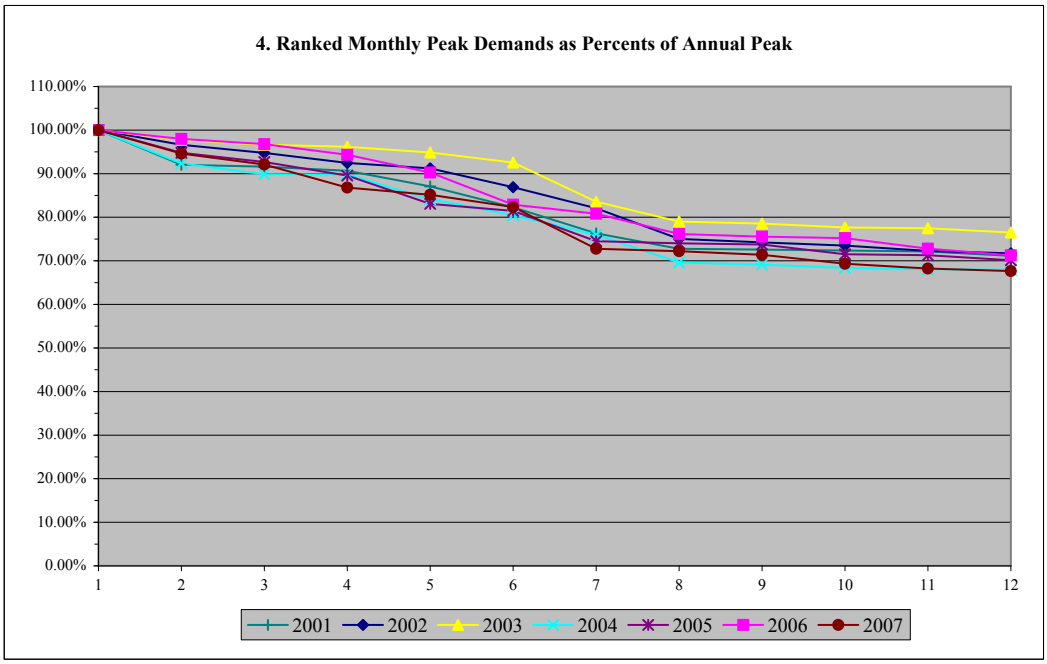


BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

1. Basic Review of Historical Monthly Peaks (Continued)





BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

2. Analysis of 12-CP Allocation Method

Line	Description	2001	2002	2003	2004	2005	2006	2007
	Basic Ratio Tests for 12-CP Method							
	Annual Peak vs. Minimum Monthly Peak							
1	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
2	Lowest Monthly Peak	6,400,000	6,234,000	6,487,000	6,537,000	6,618,000	6,640,000	6,843,000
3	Ratio Lowest Monthly to Annual Peak	71.15%	71.72%	76.49%	67.96%	70.13%	71.27%	67.67%
	7-year Range							
4	Maximum							76.49%
5	Minimum							67.67%
6	Simple Average							70.91%
	Excluding 2003							
7	Maximum							71.72%
8	Minimum							67.67%
9	Simple Average							69.98%
	Average Peaks to Annual Peak							
10	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
11	Average 12 Monthly Peaks	7,353,417	7,321,333	7,426,000	7,660,917	7,681,583	7,873,083	8,112,667
12	Ratio Average to Annual Peak	81.75%	84.23%	87.56%	79.64%	81.40%	84.50%	80.22%
	7-year Range							
13	Maximum							87.56%
14	Minimum							79.64%
15	Simple Average							82.76%

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

3. Analysis of 3-CP Allocation Method

Line	Description	2001	2002	2003	2004	2005	2006	2007
	Basic Ratio Tests for 3-CP Allocation Method							
	Peak Months: November-January							
	Difference Between Average Peak Months and Average Off-Peak Months							
1	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
2	Average Peak Months	8,463,333	8,442,667	8,322,667	9,048,333	9,043,667	9,153,667	9,665,000
3	Ratio to Annual Peak	94.09%	97.13%	98.13%	94.07%	95.83%	98.25%	95.57%
4	Average Non-Peak Months	6,983,444	6,947,556	7,127,111	7,198,444	7,227,556	7,446,222	7,595,222
5	Ratio to Annual Peak	77.64%	79.93%	84.04%	74.84%	76.59%	79.92%	75.10%
6	Difference Avg. Peak Months Over Avg. Non-Peak Months	16.45%	17.20%	14.10%	19.23%	19.24%	18.33%	20.47%
	7-year Range							
7	Maximum							20.47%
8	Minimum							14.10%
9	Simple Average							17.86%
	Ratio of Average Off-Peak Months to Average Peak Months							
10	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
11	Average Peak Months	8,463,333	8,442,667	8,322,667	9,048,333	9,043,667	9,153,667	9,665,000
12	Ratio to Annual Peak	94.09%	97.13%	98.13%	94.07%	95.83%	98.25%	95.57%
13	Average Non-Peak Months	6,983,444	6,947,556	7,127,111	7,198,444	7,227,556	7,446,222	7,595,222
14	Ratio to Annual Peak	77.64%	79.93%	84.04%	74.84%	76.59%	79.92%	75.10%
15	Ratio Avg. Peak Months to Avg. Non-Peak Months	82.51%	82.29%	85.63%	79.56%	79.92%	81.35%	78.58%
	7-year Range							
16	Maximum							85.63%
17	Minimum							78.58%
18	Simple Average							81.41%
	Off-Peak Months in Current Year Exceeding Lowest Peak Month							
19	Lowest Peak Month of Year	8,154,000	8,238,000	8,196,000	8,643,000	8,747,000	9,016,000	9,315,000
20	Number Non-Peak Months Greater	1	0	0	0	0	0	0
21	Three or More?	No	No	No	No	No	No	No
	Off-Peak Months Exceeding Prior Minimum On-Peak Month							
22	Lowest Peak Month of Prior Year		8,154,000	8,238,000	8,196,000	8,643,000	8,747,000	9,016,000
23	Number Non-Peak Months Greater		0	0	1	0	1	0
24	Cumulative Number of Occurences							2
25	Cumulative Greater than 10							No

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

4. Analysis of 3-CP Allocation Method

Line	Description	2001	2002	2003	2004	2005	2006	2007
	Basic Ratio Tests for 3-CP Allocation Method							
	Peak Months: December-February							
	Difference Between Average Peak Months and Average Off-Peak Months							
1	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
2	Average Peak Months	8,476,333	8,339,667	8,309,667	9,046,667	8,945,667	9,040,667	9,220,000
3	Ratio to Annual Peak	94.23%	95.95%	97.98%	94.05%	94.79%	97.03%	91.17%
4	Average Non-Peak Months	6,979,111	6,981,889	7,131,444	7,199,000	7,260,222	7,483,889	7,743,556
5	Ratio to Annual Peak	77.59%	80.33%	84.09%	74.84%	76.93%	80.33%	76.57%
6	Difference Avg. Peak Months Over Avg. Non-Peak Months	16.65%	15.62%	13.89%	19.21%	17.86%	16.71%	14.60%
	7-year Range							
7	Maximum							19.21%
8	Minimum							13.89%
9	Simple Average							16.36%
	Ratio of Average Off-Peak Months to Average Peak Months							
10	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
11	Average Peak Months	8,476,333	8,339,667	8,309,667	9,046,667	8,945,667	9,040,667	9,220,000
12	Ratio to Annual Peak	94.23%	95.95%	97.98%	94.05%	94.79%	97.03%	91.17%
13	Average Non-Peak Months	6,979,111	6,981,889	7,131,444	7,199,000	7,260,222	7,483,889	7,743,556
14	Ratio to Annual Peak	77.59%	80.33%	84.09%	74.84%	76.93%	80.33%	76.57%
15	Ratio Avg. Peak Months to Avg. Non-Peak Months	82.34%	83.72%	85.82%	79.58%	81.16%	82.78%	83.99%
	7-year Range							
16	Maximum							85.82%
17	Minimum							79.58%
18	Simple Average							82.77%
	Off-Peak Months in Current Year Exceeding Lowest Peak Month							
19	Lowest Peak Month of Year	8,154,000	7,929,000	8,157,000	8,638,000	8,453,000	8,789,000	8,778,000
20	Number Non-Peak Months Greater	1	2	1	1	1	1	1
21	Three or More?	No	No	No	No	No	No	No
	Off-Peak Months Exceeding Prior Minimum On-Peak Month							
22	Lowest Peak Month of Prior Year		8,154,000	7,929,000	8,157,000	8,638,000	8,453,000	8,789,000
23	Number Non-Peak Months Greater		1	2	1	1	1	1
24	Cumulative Number of Occurences							7
25	Cumulative Greater than 10							No

BC Hydro
2007 Rate Design Application

Linxwiler Analysis of BC Hydro's Monthly Peak Demands For Fiscal Years 2001-2007

5. Analysis of 4-CP Allocation Method

Line	Description	2001	2002	2003	2004	2005	2006	2007
	Basic Ratio Tests for 4-CP Allocation Method							
	Peak Months: November-February							
	Difference Between Average Peak Months and Average Off-Peak Months							
1	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
2	Average Peak Months	8,417,500	8,314,250	8,281,250	8,945,750	8,896,000	9,062,500	9,443,250
3	Ratio to Annual Peak	93.58%	95.65%	97.64%	93.00%	94.27%	97.27%	93.38%
4	Average Non-Peak Months	6,821,375	6,824,875	6,998,375	7,018,500	7,074,375	7,278,375	7,447,375
5	Ratio to Annual Peak	75.84%	78.52%	82.52%	72.96%	74.96%	78.12%	73.64%
6	Difference Avg. Peak Months Over Avg. Non-Peak Months	17.74%	17.14%	15.13%	20.04%	19.30%	19.15%	19.74%
	7-year Range							
7	Maximum							20.04%
8	Minimum							15.13%
9	Simple Average							18.32%
	Ratio of Average Off-Peak Months to Average Peak Months							
10	Annual Peak	8,995,000	8,692,000	8,481,000	9,619,000	9,437,000	9,317,000	10,113,000
11	Average Peak Months	8,417,500	8,314,250	8,281,250	8,945,750	8,896,000	9,062,500	9,443,250
12	Ratio to Annual Peak	93.58%	95.65%	97.64%	93.00%	94.27%	97.27%	93.38%
13	Average Non-Peak Months	6,821,375	6,824,875	6,998,375	7,018,500	7,074,375	7,278,375	7,447,375
14	Ratio to Annual Peak	75.84%	78.52%	82.52%	72.96%	74.96%	78.12%	73.64%
15	Ratio Avg. Peak Months to Avg. Non-Peak Months	81.04%	82.09%	84.51%	78.46%	79.52%	80.31%	78.86%
	7-year Range							
16	Maximum							84.51%
17	Minimum							78.46%
18	Simple Average							80.68%
	Off-Peak Months in Current Year Exceeding Lowest Peak Month							
19	Lowest Peak Month of Year	8,154,000	7,929,000	8,157,000	8,638,000	8,453,000	8,789,000	8,778,000
20	Number Non-Peak Months Greater	0	1	0	0	0	0	0
21	Three or More?	No	No	No	No	No	No	No
	Off-Peak Months Exceeding Prior Minimum On-Peak Month							
22	Lowest Peak Month of Prior Year		8,154,000	7,929,000	8,157,000	8,638,000	8,453,000	8,789,000
23	Number Non-Peak Months Greater		0	1	0	0	0	0
24	Cumulative Number of Occurences							1
25	Cumulative Greater than 10							No

Terasen Gas Inc. Information Request No. **1.9.1** Dated: **April 11, 2007** British Columbia Hydro & Power Authority Response issued **April 30, 2007**	Page 1 of 1
British Columbia Hydro & Power Authority **BC Hydro 2007 Rate Design Application**	**Exhibit:** **B-3**

9.0 Reference: Exhibit B-1, Page 13, Figure 1

Preamble: Figure 1 provides a chart of the rate class contributions to the monthly coincident peak demand with the smaller volume rate classes (Residential and GS<35 kW) at the bottom and the largest volume rate class (Transmission) at the top.

1.9.1 Please provide a revised version of Figure 1 with the order of customer classes reversed. In other words, please redo Figure 1 with the customer class order from bottom to top being Transmission Service, Street Lighting, Irrigation, General Service >35 kW, General Service <35 kW and Residential.

RESPONSE:

The requested figure is provided below.