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TESTIMONY OF DAVID A. SPRINGS

FPC DOCKET NO. E-7685

Q Please state your name and place of residence.

A David A. Springs, 4514 North Peachtree Road, Chamblee, Georgia.

Q Would you state your educational background, please.

A I was graduated from Georgia Institute of Technology in 1948 with a Bachelor of Electrical Engineering Degree, and again in 1949 with a Degree of Master of Science in Electrical Engineering.

Q Would you state briefly your experience.

A During graduate work at Georgia Tech, I had the unique experience of working 15 months as Assistant Operator of the Georgia Tech AC Network Calculator. At that time, the calculator was the most advanced tool for studying the overall operations of power systems. This experience gave me a very early understanding of load flow and stability problems on large utility systems.

After graduation, I worked for Southern Engineering Company in Atlanta, Georgia, for approximately three years doing distribution design work, transmission system design, and long-range power supply planning.

From 1952 to 1963, I was with the South Carolina Public Service Authority, first as Supervisor in Charge

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of Wholesale Billing, and then for a period of six years as their Planning Engineer.

Since returning to Southern Engineering Company of Georgia in 1963, I have been in charge of the Power Supply Planning and Power System Planning Section.

Q Are you a registered professional engineer?

A Yes, I am registered in the State of Georgia.

Q To what scholastic and professional societies do you belong?

A I am a member of the IEEE and the Georgia Society of Professional Engineers. I am also a member of Tau Beta Pi (Scholastic Engineering) and the Eta Kappa Nu (Scholastic Electrical).

Q Have you ever testified in other Federal Power Commission cases?

A Yes. I have previously testified in the following proceedings: Georgia Power Company, FPC Docket No. E-7548; Carolina Power and Light, FPC Docket No. E-7564; Duke Power Company, FPC Docket No. E-7557; and Mississippi Power Company, FPC Docket No. E-7625. I have also submitted my direct testimony for the Florida Power Corporation Case, FPC Docket No. E-7679.

Q By whom is your firm retained in this proceeding?

A Vermont Electric Cooperative, Inc.

Q What was your assignment?

A My assignment in this proceeding was a limited one. It was to determine the reasonableness of the 90% "ratchet" provision contained in the Central Vermont Public Service Corporation (CVPS) proposed Resale Service Rate "R" Schedule as to whether such a ratchet can or should be based upon demand data occurring prior to the effective date of the rate schedule containing the ratchet provision.

Q What material and information did you review in carrying out your assignment?

A The CVPS Monthly Operating Reports for the years 1970 and 1971, the FPC Form 1 and Form 12 Reports of CVPS for the same years, CVPS's proposed Resale Service Rate "R" Schedule, CVPS's Statement "M" filing, and testimony filed by various witnesses in this proceeding, each in part as they relate specifically to my assignment.

Q Would you first explain what is meant by a "demand ratchet provision".

A It is a rate-making device which may be used in the

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design of an electric power rate schedule, when appropriate, to cause either the pricing elements in the rate schedule to reflect the cost elements being priced, to levelize the revenues from demand charges over a period of time (usually one year) or to encourage improvement in load factor. Essentially, the ratchet sets the minimum billing demand charge in any month relative to the maximum peak demand required by the customer during a preceding period of time.

Stated in its simplest form, it may be said that a rate schedule usually attempts to price two basic elements: the demand element and the associated energy element. The demand element is a measure of capacity or capability of delivering power and is usually expressed in kilowatts (KW) or kilovolt-amperes (KVA). The second element, the energy element, attempts to put a price on the accumulated hour-by-hour use of the demand or capacity element, and is usually expressed in kilowatt-hours. In effect, the demand element is usually measured as the maximum rate of using energy throughout the billing period which is usually one month. It is simply the maximum kilowatt-hours taken per hour and therefore expressed in kilowatts.

Since the first element, or the demand element, determines the capacity that must be built into the facilities provided by the utility for a service, this is the element the utility would use in attempting to recover its costs which are fixed in nature and do not vary with the amount of energy actually delivered. These costs are primarily those costs associated with investment plus certain operating costs which tend to be fixed. All other costs, which would tend to vary with the amount of energy produced and sold, would be recovered by the utility through the energy or KWH pricing element. It is the KW element, or the element associated with fixed costs, in which the demand ratchet provision would come into play if found necessary in a rate schedule to properly recover fixed costs for the utility, or if found desirable to levelize revenues.

The demand ratchet provision usually states simply that, in the determination of billing demand for any billing month, the billing demand shall not be less than a certain percentage of the maximum demand established during the previous year. This, in effect, allows for the pricing of fixed cost elements to continue at the necessary or desired level even though the use by the customer or group of customers might drop below the "minimum billing demand" established by the ratchet.

Q How do you determine whether a given demand ratchet is necessary to recover fixed costs of the utility?

A Stated very basically, the necessity of a demand ratchet provision in the rate schedules of a utility usually develops when, throughout the annual cycle of operation of the utility's facilities, there is generating or transmitting capacity which sits idle seasonally and is otherwise unsold and not necessary or usable as needed reserve capacity. If there is no such capacity standing for periods of time unused on a utility system, there is no necessity for that utility to incorporate demand ratchet provisions in its rate schedule. With this simple test as a measure of the need for demand ratchet provisions in rate schedules, there are at least five conditions or circumstances on the utility's system which should be considered and taken into account in determining whether a ratchet provision is necessary

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to recover fixed costs and, if so, at what level the ratchet should be set:

(1) Seasonally varying fixed costs. If a utility has a seasonally varying fixed cost pattern, which is similar to its seasonal load pattern, the utility would not have fixed costs in the off-peak season to be recovered through a ratchet provision.

(2) Diversity between seasonal load patterns of customers or classes of customers. To the extent that customers or classes of customers tend to use their maximum demands during different seasons of the year, there would be a certain amount of installed capacity and related fixed costs that would be put to double use and therefore would not be standing idle seasonally.

(3) Maintenance and other reserve capacity requirements. To the extent that capacity which is normally sold to customers during peak requirement periods seasonally is used in the off-season for maintenance purposes (in other words, used in the place of facilities that are then being maintained),

there is a certain amount of capacity that is thereby not standing idle seasonally. Incidentally, some utilities are actually "maintenance saturated" whereby they are maintaining generating equipment over their annual peak because they do not have enough capacity in their seasonally off-peak periods to carry out their maintenance program.

(4) The ability to exchange capacity seasonally with other utilities. If a utility is located within practical transmission distance of other utilities which have seasonally different load patterns, there is a resulting capability for exchanging capacity seasonally with such utilities. This not only tends to reduce the utility's investment in generating facilities, but it also makes good use of some of the off-season capacity which might otherwise be standing idle.

(5) Having the ability to buy and the market to sell capacity and/or energy on an "emergency" basis. A utility which has interconnections and arrangements which give it sources to purchase "emergency" capacity and/or energy and the market to sell

"emergency" capacity and/or energy is accordingly able to reduce reserve capacity requirements and to obtain some revenue from seasonally off-peak capacity which may otherwise stand idle.

Q. Have you analyzed CVPS's proposed 90% demand ratchet to determine whether it is necessary to recover CVPS's fixed costs?

A. Taking each of the five conditions which I have just described which tend to measure the necessity for a ratchet provision to recover fixed costs, I found the following:

(1) Since the overall determination of the need for a ratchet provision in a rate schedule is a cumulative thing, the most prominant circumstance or condition affecting it should be considered first. In the case of the CVPS system in this filing, by far the most pronounced circumstance which tends to affect this consideration is the fact that the fixed costs on the CVPS system varies considerably on a monthly basis. In those months of the year when the CVPS load is highest, its fixed costs tend to be highest; and in those months when the CVPS load is lowest, their fixed

costs tend to be lowest. My Exhibit _____(DAS-1), entitled "Monthly Comparison of Total Available Generation with Monthly Peak Loads for the Years 1970 and 1971", shows a bar graph by months of the total generation capability and the monthly peak load of the CVPS system for each month of both the Test Year 1970 and the year 1971. It will be noted that the graphs show that the total generation capability available to CVPS varies considerably throughout the year and also to a considerable extent follows the pattern of the monthly peak load. This is a result of the fact that CVPS purchases a very large percentage of its total generation capability. For instance, in December, 1970, it purchased approximately 73%, and in June, 1970, it purchased approximately 60%. In other words, in December of 1970, CVPS purchased 247 megawatts out of a total generation capability of 338 megawatts, and in June, 1970, CVPS purchased 141 megawatts out of a total generation capability of 232 megawatts. Quite a large percentage of these purchases are either short-term purchases or allow for seasonal variations which result in the pattern shown in

Exhibit _____ (DAS-1).

Q What is the source of CVPS's purchased power?

A There are many and varied sources throughout New England plus the Power Authority of the State of New York plus the New Brunswick system in Canada. A list of the sources and a tabulation of the amounts of the purchases by months is shown on Witness Chayavadhanangkur's Exhibit _____ (JC-1), pages 3 and 4.

Q How is it possible that CVPS is able to tap such wide and varied sources for purchased power?

A CVPS obtains power over the interconnected transmission systems of New England and New York into the State of Vermont and then over the VELCO system into CVPS, under many varied contractual arrangements.

Q How is Central Vermont able to pattern its seasonal purchases generally in accordance with its seasonal needs?

A It is in part due to the coordinated planning of the utilities in the entire area as to the scheduling of new generation. It is also due in part to the fact that the interconnected systems of New England and New York are able to exchange capacity seasonally during the winter peaking months of upper New England and the summer peaking months of New York City up into Massachusetts. This is being done under a number of varied contractual arrangements which I am personally not familiar with, but the effect of it does reach up into Vermont. A good example of this is the contract which CVPS has with the Boston Edison system (actually purchased and brought into the State by the VELCO system) which provides for the following seasonally varying capacity purchases:

July 1, 1970 to September 30, 1970	44,476 Kilowatts
October 1, 1970 to May 31, 1971	127,497 Kilowatts
June 1, 1971 to September 30, 1971	8,903 Kilowatts
October 1, 1971 to May 31, 1972	44,605 Kilowatts
June 1, 1972 to September 30, 1972	8,903 Kilowatts
October 1, 1972 to May 31, 1973	44,605 Kilowatts
June 1, 1973 to September 30, 1973	8,903 Kilowatts
October 1, 1973 to May 31, 1974	44,605 Kilowatts
June 1, 1974 to September 30, 1974	8,903 Kilowatts
October 1, 1974 to May 31, 1975	118,602 Kilowatts
June 1, 1975 to September 30, 1975	44,605 Kilowatts

The varying seasonal availability is obvious.

Q What do you conclude from this?

A I conclude that CVPS through the purchasing agreements it has with other utilities has been able successfully to fairly closely match its total available generation capacity to its monthly peak load. There are occasional excesses above needs to meet loads from time to time, but the amount of excess has no consistent relationship with previous system peaks. The monthly pattern itself is not even consistent, as would be indicated by comparing Sheets 1 and 2 of the Exhibit _____ (DAS-1). This certainly shows that a demand ratchet based upon the previous peak demand has very little place in the cost patterns of CVPS. Incidentally, this shows very strongly that the 12-month average coincident demand method of allocating fixed costs is the proper method.

Q Please continue with your analysis of CVPS's ratchet as to each of your five criteria.

A Continuing with the second condition:

(2) A cursory review of delivery point metering data within the wholesale for resale customer class indicates there would be some but not a great deal of seasonal diversity between the delivery points. I did not have

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the time to make a detailed study here, but this would be somewhere between 5% and 10%. This would tend to say that there is a doubling up on the sale of capacity seasonally within the wholesale for resale class, which would tend to reduce the need for a demand ratchet by approximately 5% to 10%.

(3) The need for seasonally off-peak capacity to meet scheduled maintenance is not obvious on the CVPS system. This is due, of course, to the fact that the CVPS system has only a small amount of generating capacity in its system. However, the same effect comes into play with the "unit purchases" of CVPS from the outside which are not otherwise firmed. In effect, when these unit purchases are from generating units which are down for maintenance purposes, they must be replaced by CVPS with other capacity. Since it is normal for such units to be scheduled for maintenance in the months of the year when the area loads are lowest, in effect these maintenance reserve kilowatts would have a tendency to be used for this purpose and otherwise not stand idle in the off-peak months on the CVPS system.

(4) In my test of CVPS's ability to exchange capacity seasonally with other utilities, this is definitely an effective consideration. However, it has been accomplished in a round-about way to a considerable extent through the seasonal purchases discussed under paragraph (1) above.

(5) A cursory review of the Operating Reports of CVPS indicates that, in the month-to-month operation of its system, it is able to sell considerable quantities of capacity and energy either as emergency power or otherwise. This would definitely have a tendency to make at least partial use of seasonally available capacity which would otherwise stand idle.

Q What conclusions have you reached from this analysis?

A Most of the conditions or circumstances discussed in paragraphs (1) through (5) above would tend to indicate that a ratchet provision is not necessary to recover CVPS's fixed costs and probably not even desirable in the Resale Service Rate "R" Schedule. Taken together, they definitely show that a 90% demand ratchet provision is much too stringent and is out of place in this filing as a device to recover fixed costs.

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Since the 90% demand ratchet is not necessary to recover CVPS's fixed costs, it would appear that it has been included in the rate schedule as a device to levelize revenues from the demand component of the rate schedule over the summer and winter seasons.

Q Have you analyzed CVPS's 90% demand ratchet to determine whether it is appropriate in this instance as a device to levelize revenues?

A Yes. In some instances on a utility system, there is consistent similarity in the seasonal load patterns of the customers in a given class. In this case, if all such customers have the same seasonal load patterns, no customer is advantaged or disadvantaged with respect to the others in the class by the application of a ratchet or the non-application of a ratchet. In such cases, then, a ratchet may be used as an incentive to improve load factor, or it may be applied in order to levelize annual revenue. In this instance there is no evidence that the primary purpose of CVPS's ratchet is as an incentive to improve load factor. As I indicated above, the purpose of the 90% ratchet provision in the proposed resale Service Rate "R" Schedule appears to be to levelize revenues. However, an analysis of the seasonal load patterns of purchases by different wholesale for resale customers to be served under Rate "R" Schedule shows that the summer to winter peak comparisons among these customers varies quite widely, which will cause certain of them to be unfairly disadvantaged by the application of a ratchet for revenue levelizing purposes.

Q What is the effect of CVPS's 90% demand ratchet as applied beginning June 28, 1972, based upon demands occurring during the winter 1971-1972?

A Since the demand ratchet is not in this case a device to recover actual fixed costs, but is instead a device to levelize revenues, the effect is to spread a portion of revenue related to CVPS's winter 1971-1972 sales over to the summer 1972 period but at increased rates. In other words, Vermont Electric Cooperative is paying again, at increased rates, for services it received from CVPS and paid for at then existing rates during the 1971-1972 winter period.

Q Mr. Springs, I hand you Exhibit _____ (DAS-2) consisting of six pages, and entitled "Vermont Electric Cooperative,

Inc. Computation of Demand Charge Difference for 1972 Applying Former Contract Ratchet Provisions, versus 90% Ratchet, both After June 28, 1972."
Was this Exhibit prepared under your direct supervision?

A Yes, it was.

Q Would you describe the Exhibit, please.

A This Exhibit was prepared at the request of the Cooperative, to show the very severe effect of the application of a 90% demand ratchet during the year 1972; if made effective along with Resale Service Rate "R" Schedule on June 28, 1972; and is based on previous peak demands registered in the winter months prior to the effective date of the new rate schedule. The computations are presented in tabular form and are based on actual billing data for the early part of the year and estimated billing data through December, 1972. The computations are similar in every way except for the ratchet provisions assumed. In both computations, the rates and charges of the proposed Resale Service Rate "R" Schedule are assumed to be in effect for the months of July through December; but in one case the demand billing computations are based upon the 90% demand ratchet of Resale Service Rate "R" Schedule, and in the other case, the demand billing computations are based on ratchet provisions existing in previously applicable schedules. Page 1 of the Exhibit is a summary page showing a comparison of the computation based on 90% demand ratchet shown in Column (c) and the computation based upon the former demand ratchet provisions shown in Column (d) with the difference in resulting billing demands shown on Line 1 under Column (e) and the dollar difference shown on Line 2 in Column (e). Pages 2 and 3 show the dollar computations and the billing demand determinations, respectively, for the 90% ratchet assumption. Pages 4 and 5 show the dollar computation and the billing demand determination, respectively, utilizing the former contract demand ratchet provisions. The total amount of the increase is $64,844.

Q Could the retroactive application of this ratchet have any other adverse effect on Vermont Electric Cooperative?

A Yes, definitely so. Assume that the Vermont Yankee Nuclear plant goes into commercial operation on

October 15, 1972 as contemplated by NEPEX as of May 1, 1972. Vermont Electric Cooperative is committed to purchase its 5,583 KW of Vermont Yankee power from and after that date. When the Cooperative starts taking its committed amount of power from Vermont Yankee, this will reduce its required capacity demand from CVPS by the 5,583 KW. Therefore, it will be paying CVPS for the original amount of unused ratcheted demand plus this additional 5,583 KW demand which is now excess to their needs. This is a doubling up of cost on Vermont Electric Cooperative which is unreasonable and uncalled for. CVPS, in addition to collecting these sums from the Cooperative, can now, through their access via VELCO and NEPEX, sell this capacity to other utilities in New England. In effect, CVPS is charging its customers for capacity the customer can't use, and then selling this capacity to others; thus collecting twice for the same item. Incidentally, if commercial operation of Vermont Yankee is further delayed until early 1973 and after the Cooperative has established its new winter peak, the above described circumstances will exist throughout the remainder of 1973.

The 90% ratchet is very punitive in this case and is out of place.