PUBLIC UTILITIES COMMISSION OF NEVADA

Docket No. 01-11029

Nevada Power Company

DIRECT TESTIMONY OF

Bruce Edward Biewald

February 20, 2002

Q. PLEASE STATE YOUR NAME, BUSINESS POSITION AND ADDRESS.

A. My name is Bruce Edward Biewald. I am president of Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. PLEASE DESCRIBE YOU EMPLOYMENT, QUALIFICATIONS, AND EXPERIENCE?

A. I am president and owner of Synapse Energy Economics, Inc., a consulting company specializing in economic and policy analysis of the electricity industry, particularly issues of restructuring, market power, electricity market prices, consumer protection, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies on a broad range of electric system regulatory and policy issues. I have testified on energy issues in more than seventy-five regulatory proceedings in twenty-five states and two Canadian provinces. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. I also have consulted for federal agencies, including the Department of Energy, the Department of Justice, the Environmental Protection Agency, and the Federal Trade Commission. Details of my experience are provided in Attachment BEB-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have reviewed Nevada Power Company's (NPC) procurement of power for the period March 1, 2001 to September 30, 2001. I am presenting my conclusions from that review.

Q. HOW DID YOU GO ABOUT CONDUCTING YOUR REVIEW?

A. I analyzed the Company's filing in this case, including the prefiled direct testimony of Mike Smart, Jon Perry, and Charles Hunter, the "primer" and the "primer appendix." I reviewed NPC's responses to the Staff's data requests and the data requests of other parties. Working with staff at Synapse Energy Economics, I analyzed the quantities and prices of products purchased by the Company over time, using transaction data provided by the Company and other market data. I also read the depositions taken in this case.

Q. WHAT ARE YOUR CONCLUSIONS FROM YOUR REVIEW OF NPC'S POWER PROCUREMENT?

A. My main conclusions are as follows:

- NPC's procurement for the summer of 2001 relied heavily upon the purchase of "standard products," most importantly the 6x16 blocks of firm power purchased on a calendar quarter (July to September) basis.
- Reliance upon 6x16 blocks created problems for system operations, and resulted in large amounts of economy sales in the early morning at very low prices.
- The purchase of power by calendar quarter resulted in excess purchases for September, NPC's lowest load month of the three months in the third quarter.
- NPC's procurement strategy was based in part upon the expectation that surplus energy could be profitably sold off-system or the simplistic view that "the risk of being short was greater than the risk of being long" so that price did not figure into the decision-making about how much power to purchase.
- Using the "standard" 6x16 product to cover peak hour demand has an extraordinarily high effective price per MWh actually needed to serve load. For example, a $400/MWh 6x16 purchase for the third quarter, if it were only needed for 20 hours would have an effective price of $24,000/MWh.

- NPC's February 2001 purchase of 275 MW on-peak power for Q3 (the "above average" strategy) at an average price of $419/MWh had a total cost of $140 million,[1] and an effective price of $7,720/MWh, since it was expected to be needed for only about 66 hours during the quarter.
- The February 2001 purchases for Q3 totaled about $156 million (for the on-peak and off-peak products) but the value of those purchases turned out to be only about $23 million – for a net loss of $133 million.
- NPC's April 2001 purchase of 125 MW of on-peak power for Q3 at an average price of $513/MWh had a total cost of about $78 million,[1] and an effective price of $33,000, since it was expected to be needed for only about 19 hours in the third quarter.
- The April 2001 purchases for Q3 totaled about $106 million (for the on-peak and off-peak products) but the value of those purchases turned out to be only about $15 million – for a net loss of $92 million.
- NPC appears not to have analyzed the appropriate mix of products to meet its system requirements. Rather, its analyses focused upon comparisons of products with each other.
- NPC abandoned its RFP and bilateral procurement processes, which offered at least some prospects for obtaining products that would better fit its needs.
- NPC appears to have overlooked or discounted indications that market forces or regulatory actions would address high summer prices in the Western markets prior to the summer of 2001.
- NPC apparently based its decisions upon deterministic price forecasts, and failed to conduct analysis of price uncertainty and its implications for its strategy.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized in four sections, as follows. First, I provide some background on the Company's efforts to procure power from the fall of 2000 into the summer of 2001. Second, I discuss the price trends in the Western markets, including the factors driving the increase and the subsequent decline. Third, I examine the impact of the 6x16 blocks of power upon system

[1] There was also a similar purchase in February for the second quarter of 2001 (at $271/MWh), and there was off-peak power purchased in February for the second and third quarters as well.

operations. Fourth, I discuss aspects of NPC's decision-making process as it relates to procuring resources to serve load through this period, particularly the third quarter of 2001. And finally I comment on a few miscellaneous issues and summarize my conclusions.

Background on NPC's Power Procurement

Q. HOW DID NPC GO ABOUT PURCHASING POWER FOR THE SUMMER OF 2001?

A. NPC's procurement for the Summer of 2001 is summarized graphically in Attachment BEB-2. The purchasing began in May of 2000 with purchases mainly for delivery at Palo Verde. The Palo Verde "hub" is an actively traded market for electricity, physically located in Southwest Arizona. In October of 2000, NPC began purchasing substantial quantities of power for delivery at Mead. By the beginning of November of 2000, NPC had purchased about 800 MW of on-peak power for the third quarter (Q3) of 2001, and the Company's Risk Management Committee was targeting an additional 800 MW of on-peak purchases for Q3 of 2001. Those purchases were made in November, December, and January.

In February of 2001, the Company decided to purchase an extra 250 MW. This was termed the "above average" strategy, and it was based upon a recommendation from Jim Joyce, a risk management consultant to NPC. It appears that NPC actually purchased 275 MW of 6x16 power for Q3 in February, at an average price of $419/MWh. Around the same time (the latter portion of February) NPC also purchased 100 MW of off-peak power for Q3, at an average price of $159/MWh. At the same time, NPC also purchased on-peak and off-peak power for Q2. The total cost of the on-peak power for Q3 was $140 million.

Q. DID NPC BUY ADDITIONAL POWER FOR Q3 AFTER FEBRUARY?

A. Yes, most notably in the beginning of April 2001, NPC purchased an additional 125 MW of on-peak power for Q3. At this point, the price was at about $513/MWh, and the total cost of these April

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[1] This treats the "custom 2" purchase as a 6x16 block. There was also some off-peak power purchased in April as well.

purchases of on-peak power for Q3 was $78 million. There were off-peak purchases for 100 MW made at the same time for Q3, at an average price of $159/MWh.

Q. WHAT POWER PRODUCTS DID NPC PURCHASE?

A. NPC's purchases are almost entirely the "standard" products traded in the Western power markets. Specifically, on-peak or heavy load power ("6x16s"); off-peak or low load power (delivery between 10 pm and 6 am, plus Sundays); and base load power ("7x24s"). The 6x16 power blocks typically deliver from 6:00 am to 10:00 pm, except for Sundays and holiday. The off-peak power delivers for exactly the opposite time period. The 7x24 power delivers for all hours of the month or quarter. All of these standard products were commonly traded in 25 MW increments.

Q. AT WHAT DELIVERY POINTS DID NPC PURCAHSE POWER?

A. NPC purchased power at the following delivery points:

- Palo Verde
- SP-15
- Mead
- Four Corners
- McCullough
- Navaho
- Nevada-Oregon Border/Nevada-Utah Border

Of these, the major delivery point for power actually used by the NPC system is Mead.

Q. HOW DID THE DIFFERENT DELIVERY POINTS FIGURE INTO NPC'S PROCUREMENT APPROACH?

A. NPC actually made most of its purchases at Palo Verde, at least initially. After buying power for delivery at Palo Verde, NPC would then at a later point enter into a matched pair of transactions selling the Palo Verde power and buying an equal amount of power for delivery at Mead. Attachment BEB-2 lists NPC's position for July 2001, by month by delivery point, showing the purchases at Palo Verde beginning in May of 2000 and continuing through June 2001, as well as the purchases of power at Mead growing from October 2000 through June 2001.

There was a significant price spread between the Palo Verde and Mead delivery points. The spread for on peak power grew from about $5/MWh in September 2000 to about $75/MWh in March

2001, and then declined back to about $5/MWh by August 2001 (NPC Response to Staff 122). The Company's explanation for these price trends is that marketers knew that NPC needed to purchase energy and transmission to Mead for summer 2001, and that they bought and hoarded energy and transmission in advance. (Response to Staff 81)

For power deliveries to NPC's system in the third quarter of 2001, NPC paid a total of $94 million just for the "spread." I calculated this figure by matching sales at Palo Verde with simultaneous purchases at Mead or McCullough, and totaling the price differentials. The Company has described this two-step strategy in its filing in this case, but has not provided information supporting the value of this strategy, or explaining why the basis differential was so volatile. The trends in the basis differential are cause for concern, particularly given the size of the costs incurred by NPC in this period.

Q. HOW DO 6X16 POWER BLOCKS FIT WITH NPC'S SYSTEM NEEDS?

A. The 6x16 standard product does not fit the NPC system well. NPC's loads are very peaky and Sunday loads are high. With Las Vegas' emphasis on tourism, Sundays are not much different from other days of the week in terms of demand levels. I will discuss this issue, and the implications for surplus energy and system operations, later in my testimony.

Q. DID PRICE FIGURE INTO NPC'S DECISIONS ABOUT HOW MUCH POWER TO PURCHASE?

A. No. The Company's response to Staff 122 part F, states plainly that with regard to the Company's procurement targets that "the prices for purchased power did not enter into the determination of these quantities."

Electricity Prices in the Western Markets

Q. PLEASE DESCRIBE THE PATTERN OF PRICES IN THE WESTERN MARKETS OVER THE PAST FEW YEARS.

A. A graph of forward prices for 6x16 power at Palo Verde in July, August, and September is presented in Attachment BEB-3. In October of 2000, the price for summer 2001 power was between $100 and

$200 per MWh, with little difference between the three Q3 months. The price increased through the winter, peaking in April of 2001, at which point the prices were at about $600/MWh, $700/MWh, and $400/MWh for deliveries in July, August, and September, respectively. From April, the prices dropped to about $100/MWh in June. The actual daily prices for 6x16 power at Palo Verde, shown in Attachment BEB-4, were under $80/MWh after the first couple of weeks, and under $30/MWh at the end of Q3.

Q. WHAT WERE THE CAUSES OF THE PRICE INCREASES IN THE WESTERN ELECTRICITY MARKETS AND THE SUBSEQUENT DECREASES?

A. The electricity market price increases were driven by a number of interrelated factors including (1) over-reliance upon the spot market in California; (2) supply-demand imbalance in the regional markets; (3) trends in input costs, most notably natural gas prices; and (4) market power in the Western wholesale markets.

California's over-reliance on the spot market was a deliberate part of the market design, with the unfortunate result of providing generators with opportunity and incentive to increase profits by physical and economic withholding. This problem was addressed in part by the California Division of Water Resources' procurement of large quantities of contract power in the early part of 2001.

The supply-demand imbalance in the West was, in part, the result of inefficient and anti-competitive capacity withholding, which was eventually addressed by the FERC. There was also a considerable market response to the "price signal," specifically adding new supply, and demand response (both through programs, and through customer response to higher prices). These actions could reasonably be expected to mitigate price increases.

The input costs most commonly cited as responsible for high western prices are fuel costs, mainly natural gas, and air emissions credits in specific local circumstances. As these input prices dropped, so did electricity prices.

And finally, the FERC's June 19, 2001 order played a role in addressing the market power problem, by extending the California price cap to the rest of the Western market, and perhaps more importantly, by requiring generators to offer their capacity to the market, ending some of the opportunities for physical withholding. Paul Peterson discusses this in his testimony in this case.

Overall, market and regulatory responses to the high prices acted to bring the prices back to levels that are more in line with costs. It was predictable that this would happen at some point. With prices far in excess of costs, regulators were under considerable pressure to address a growing regional economic disaster. To the extent that regulators would not or could not respond, the market forces of supply and demand response would have. The timing of the regulatory and market response, however, was quite uncertain.

Q. CAN YOU SAY SPECIFICALLY WHAT ROLE THE FERC'S JUNE 19, 2001 ORDER PLAYED IN BRINGING DOWN PRICES IN WESTERN ELECTRICITY MARKETS?

A. The Company has referred to the FERC's June 19, 2001 order as the cause of the price decline in Western markets (see, for example, response to Staff 115). While it is difficult to say for certain what role each factor played in causing the price drop for the summer 2001 prices, it is clear that the FERC Order itself was not the only, or even the major factor. Examination of the forward price data for Q3 of 2001 (see Attachment BEB-3) shows that the FERC's June 19, 2001 order could not have been the main factor causing the price decline since the prices had already dropped by 80 to 90 percent from the highest levels by the middle of June when that order was issued.

System Operations Implications of 16 Hour Purchase Blocks

Q. HOW DO THE "STANDARD PRODUCTS" FIT WITH THE OPERATION OF THE NPC SYSTEM?

A. The standard products (6x16s and quarterly purchases) do not fit well with the NPC's system needs. In small quantities this would not be a major concern. However, as the amounts increase, so do the problems. Most notably, the 16 hour on-peak blocks, when purchased in large quantities, create problems for the dispatch of the system.

Attachment BEB-7, page 1, has a graph of the NPC average hourly firm purchases for July. Sundays and holidays (July 4) have been removed from these averages. There is an increase of 921 MW in firm purchases, on average, at 7:00 am. This jolt to the system has the immediate result of increasing economy sales by 563 MW. The Company's fossil power plants must be at low loading in the early morning, in order to be poised to ramp up as load increases during the morning at an average rate of about 200 MW per hour.

In response to Staff 95, the Company indicated that it "has had to curtail or limit its output on many occasions" to avoid the problems of "over-generation, high frequency, trouble maintaining a balance of loads and resources and high voltage" associated with the first few hours of the 6x16 contracts.

Q. IS THERE A SIMILAR PHENOMENON AT THE END OF THE DAY?

A. The July data in Attachment BEB-7 shows the economy sales on the average day in July declining gradually over the morning hours, and a relatively small drop off in economy sales (108 MW) at 10:00 pm, when the 6x16 blocks terminate. The end of the 6x16 blocks does not produce the same magnitude of effect as the beginning of delivery in the morning. The reason for this may be seen in the graph on page 1 of Attachment BEB-8. This graph shows the total system load by hour (for the average non-Sunday in July) and the net load if the firm purchases are subtracted. The net is roughly the load that the rest of the system is dispatched to meet.[1] The net load for the hour beginning 6:00 am is actually negative.

Q. DO THE FIRM PURCHASES, ECONOMY SALES, AND NET LOADS FOR AUGUST AND SEPTEMBER LOOK SIMILAR TO THOSE FOR JULY?

A. The information for August and September is provided in additional pages on Attachments BEB-7 and BEB-8. The pattern in August is similar to July. September has generally lower loads, but on the whole September shows a similar pattern as well.

Q. WHAT DO YOU CONCLUDE FROM THESE GRAPHS?

A. The NPC system, with nearly 2000 MW of purchased power during heavy load periods and roughly half of that amount during off-peak periods, was subjected to large discontinuities at the beginning and the end of the delivery of the 16 hour products. The effect on the system was particularly pronounced during the morning, and the dispatch of NPC's resources was highly constrained by the lack of net load during the early morning.

[1] Firm sales and economy purchases are relatively quite small for this system.

NPC Decision-Making

Q. WHAT WAS THE BASIS FOR NPC'S DECISION IN FEBRUARY TO PURCHASE THE "ABOVE AVERAGE" POWER?

A. The decision in February of 2001 to purchase an additional 250 MW (the "above average" strategy) is discussed in a February 14 email from Jim Joyce and in the direct testimony of Mike Smart in this case. The reasons cited for this purchase included: (1) the expectation that NPC would buy in the spot market on hot days; (2) California's statement that it would be capacity short; (3) that the spot market was uncapped; (4) comparison of the downside and upside risks; and (5) expected planned and forced outages of generators. Two options were considered at this point: a call option with a strike price of \$500/MW and a weather contingent call option. The Company concluded that neither of these options was attractive, in part because they would have required an immediate cash outlay that would have posed a problem for NPC financially.

Based upon this email, NPC purchased 275 MW of power for Q3, at a total cost of \$140 million. It also purchased power for Q2, and for the off-peak periods in both Q3 and Q4. There was no analysis of the impact upon the total system, no analysis of alternatives beyond the two options in the email, and only very limited analysis of the risks. The February 14th e-mail is attached to Staff witness Henderson's testimony, MRH-10.

Q. WHAT WAS THE BASIS FOR NPC'S DECISION IN APRIL TO PURCHASE THE 125 MW OF POWER?

A. In April, 2001, NPC purchased 125 MW of on-peak power at an average price of \$513/MWh for Q3 of 2001. This includes 50 MW of "custom 2" power, which I am treating as standard on-peak for this calculation. NPC also purchased 75 MW off-peak power for Q3 at the same time, at an average price of \$235/MWh. I am not sure what process NPC used in deciding to make these purchases in April. I could not find a discussion of this in the materials provided by the Company in this case.

Q. WAS NPC'S DECISION TO PURCHASE POWER AT THESE PRICES IN FEBRUARY AND IN APRIL REASONABLE?

A. No. At prices for 6x16 power in the \$400 to \$500/MWh range, I believe that NPC should have conducted more thoughtful analysis, and considered a broader range of options, particularly given the market context and system operations considerations discussed above. The 6x16 on-peak blocks create a large surplus of energy, particularly when they are purchased for an entire month or an entire quarter. In using these purchases to meet the system peak hour loads, the effective price per MWh that is actually needed to serve load can be extraordinarily high. At these prices, I believe that NPC should have conducted more analysis of its alternatives, and aggressively pursued those alternatives.

Q. WHAT ARE THE EFFECTIVE PRICES PER MWH FOR THE POWER PURCHASED BY NPC?

A. Assuming a purchase price of $400/MWh, the table in Attachment BEB-6 lists the effective prices for 6x16 power if purchased on a daily, monthly, and quarterly basis. For a monthly purchase, for example, the 6x16 would deliver for about 400 hours. If it were actually needed for those 400 hours, then the effective price would be equal to the nominal price of $400/MWh. If the purchase were only need for 200 hours, however, then the effective price amounts to $800/MWh. The first blocks of 6x16 power added to the NPC system might be used more than ½ of the time, and so have an effective price in this range.

However, as the number of useful hours decreases, the effective price of the "$400/MWh" blocks increases. Specifically, at 50 hours of need, a monthly 6x16 would have an effective price of $3,200/MWh. At ten hours of need the effective price would be $16,000/MWh. Buying a monthly 6x16 to cover two hours of need, has an effective price of $80,000/MWh.

If the 6x16 blocks are purchased for a full quarter of the year, as most of NPC's purchases for the summer period were, then the effective prices per MWh are about three times higher. For example, if the need is for only 50 hours of the quarter, than the effective price for a 6x16 would be $9,600/MWh.

Q. ARE SUCH LOW NUMBERS FOR THE HOURS OF NEED REALISITIC?

A. Yes. While the first 6x16 blocks of purchases add to NPC's resource mix could reasonably be expected to be needed for a substantial number of hours, the last blocks added to the resource mix would have been needed for only a few hours. See, for example, the load duration curves in Attachment BEB-5. Page two of the Attachment zooms in on the highest 50 hours, showing, for example, that in the forecast load for July, the last 200 MW of peak load is limited to only 5 hours.

Q. WHAT WAS THE EFFECTIVE PRICE OF NPC'S ON-PEAK PURCHASES MADE IN FEBRUARY AND IN APRIL?

A. A conservative estimate for the February 275 MW purchase is that it would be needed for 66 hours, and so with its average price of $419/MWh, its effective price is $7,720/MWh. A conservative estimate for the April 125 MW purchase is that it would be needed for 19 hours, and so with its average price of $513/MWh, its effective price is $33,000/MWh.

Q. DOES THIS CALCULATION OF "EFFECTIVE PRICE" ASSUME THAT THE BUYER WOULD ONLY TAKE DELIVERY OF POWER IN THOSE FEW HOURS?

A. No. The purchases are for 16 hours, six days each week, and once the purchase is made the power will generally be taken. However, just because the power is delivered does not mean that it is needed.

Q. WAS IT POSSIBLE THAT NPC'S APPROACH OF BUYING POWER IN 16 HOUR BLOCKS TO MEET ITS PEAK PERIOD LOADS COULD HAVE WORKED OUT WELL?

A. Yes. Despite the high "effective prices" for the needed portion of this power, the approach could have worked out well if prices had stayed high or risen further. NPC's approach seems to be based upon the expectation that it could sell the surplus power at high prices. With its procurement strategy the Company would be anticipating large amounts of surplus in the shoulders of the 16 hour blocks, in the days in which load is low or merely typical, and in the months outside of the highest load periods (e.g., in September). If market prices had stayed at the levels that they were in April, or if they increased further, then NPC's surplus could have been sold at prices that would have shown the overall strategy to be profitable.

Q. WHAT WAS THE ECONOMIC LOSS ON NPC'S FEBRUARY AND APRIL PURCHASES?

A. The way things actually turned out, with low prices in the summer, NPC's strategy was economically disastrous. At actual summer 2001 prices, NPC's $156 million of February purchases for Q3 was worth only about $23 million, for a net loss of $133 million. NPC's $106 million in April purchases for Q3 was worth only about 15 million, for a net loss of $92 million.

Q. WAS IT FORSEEABLE THAT THESE LOSSES WOULD OCCUR?

A. It was not clear early in 2001 that prices for the summer would fall, but it was clear that a decline was a possibility that should have been considered in planning and power procurement.

Q. WHAT DOES NPC SAY IN THIS CASE ABOUT THE ROLE OF PRICE IN DETERMINING ITS PROCUREMENT APPROACH?

A. NPC may have been fixated on meeting its peak with 6x16 power purchases regardless of the cost. There are several statements from the Company in documents in this case that support this view. For example, on page 47 of Mr. Smart's testimony he states that "Put simply, reliability was first in our minds, and because a long position could later be sold, but short position might not have been available to be purchased (at any price), the risk of being short was greater than the risk of being long." This is an extraordinarily simplistic view. Staff asked the following question specifically with reference to that statement by Mr. Smart: "Did the Company conduct any quantitative analysis of the costs and risks of being long or short in the market to support this?" (Staff 125). The Company's response was to refer to the response and attachments to another question (BCP 7-06) which consisted of one email from Jim Joyce dated February 14, 2001, discussing his views on the alternatives to the February "above average" purchases.

Q. WHAT ALTERNATIVES TO COVER ITS PEAK DEMAND SHOULD NPC HAVE PURSUED BEYOND THE PURCHASING OF THE STANDARD 'ON PEAK' PRODUCT?

A. The Company should have pursued other products as well as "demand response" from its customers. Buying power at any price was not the only available approach. When asked, NPC's witnesses generally conclude that the market didn't provide other products 6 to 7 months out, but they kept no records or logs of alternatives considered, pursued, or offered.

Q. DID NPC MAKE REASONABLE EFFORTS TO PROCURE ON-PEAK POWER OTHER THAN THE 6X16 PRODUCT?

A. I can not say whether NPC did or did not make reasonable efforts to procure other products. What information that I have reviewed shows NPC focused on the standard products offered in the broker market. The responses to NPC's RFPs show some "non-standard products" – such as the 6x8 "super-peak" product that might have fit better with the Company's needs, at least for a portion of its peak power requirements. These products, however, appear to have become less available in the broker market over time.

The Company has pointed out that the "super-peak" power (for 8 hours during the day) was much more expensive than the 16 hour product. It provided one assertion that "when Q3 Mead was trading around $500/MWh, the super-peak product was offered at $900/MWh" (response to Staff 88). However, there was no documentation for this. When Staff requested "all futures market prices used for selecting firm purchase power contracts for delivery in May 1999 through September 2001…" (Staff 47) NPC's response was to provide data on 6x16 forward prices. It is not possible, without price data for the products that NPC did not purchase, to evaluate the economics of the decision to focus almost exclusively on standard products.

Q. COULD NPC HAVE PURCHASED A "SHAPED PRODUCT" THAT BETTER MATCHED ITS NEEDS?

A. Yes. In its response to Staff 88, NPC describes a situation in which it requested a shaped product from Pinnacle West, which responded with an offer that NPC evaluated by comparing the price to an hourly price shape derived based upon historic Cal PX hourly prices. The price for Pinnacle West's offer was found to be 10% higher, and was rejected. NPC provided no documentation of this offer or its analysis (the question requested documentation). The analysis as described did not include consideration of how the power would have fit with NPC's system needs, improved the dispatching of NPC's units, or how it would have reduced risk compared to the 6x16 alternative with all of the associated excess energy.

Q. DID NPC CONDUCT ANY SYSTEM SIMULATION MODELING, OR OTHER ANALYSES, TO DETERMINE WHAT THE APPROPRIATE MIX OF PRODUCTS WOULD BE FOR ITS SYSTEM FOR THE SUMMER OF 2001?

A. Apparently it did not. NPC was asked to identify and provide such analyses in Staff 98. In response, NPC merely provided a discussion of how it compared standard products against each other. This is consistent with the analyses that NPC did of the responses to its RFPs. That is, NPC would look at the expected market value in different hours, and compare a purchase of 6x16 block with a purchase of 6x8 product – but it apparently never analyzed the mix of products that would economically serve its system requirements. In deciding, for example, how much off-peak and on-peak power to purchase, I would expect that it would be necessary to run some analysis of the system operations, and estimate total system costs for different amounts of off-peak power.

Q. WHY DO YOU SAY THAT NPC SHOULD HAVE PURSUED DEMAND RESPONSE FOR ITS PEAK HOUR NEEDS?

A. Demand response programs can provide an effective "call option" for the Company. They can be an effective way of addressing peak demand hours at reasonable cost, even in systems that are not experiencing the high prices that occurred in Western electricity markets. Interruptible load tariffs have a long history in the electric utility industry, and recently with increased volatility in wholesale markets the use of demand response programs to address system reliability concerns in a cost-effective manner.

Q. HOW MUCH LARGE CUSTOMER BACK UP GENERATING CAPACITY EXISTS IN THE AREA?

A. I understand that there is a total of more than 200 MW of back up generating capacity owned by large customers in the NPC service territory. The operating cost for back up diesel generators is usually in the range of $100 to $200/MWh. The cost of emission credits can add significantly to this cost, depending upon the location and specific situation.

Q. WHAT ARE THE BARRIERS TO USE OF DEMAND RESPONSE TO MEET NPC'S PEAK LOADS?

A. The primary obstacles are the need for a tariff and the environmental permits for back up generators. Both of these obstacles have been successfully addressed in other parts of the country.

Q. WHY DO YOU BELIEVE THE NEED FOR A TARIFF FOR DEMAND RESPONSE COULD HAVE REASONABLY BEEN ADDRESSED?

A. Parties in the State were aware of the need for a tariff for demand response and back up generation for the summer of 2001. Progress was being made to develop and implement the "Optional Curtailment" tariff. If the prices for the summer of 2001 had not dropped, then more use could have been made of this tariff. That is, if prices had remained high, then the payments under that tariff would have provided a benefit to the Tariff participants and to the Company (see NPC response to Staff 115).

Q. WHY DO YOU BELIEVE THAT THE ENVIRONMENTAL PERMITTING REQUIREMENTS FOR DEMAND RESPONSE COULD REASONABLY BE ADDRESSED?

A. I believe that the environmental permitting restrictions that constrain the use of back up generators for demand response could have been overcome because they have been dealt with elsewhere.

Environmental regulators in other regions of the country have provided regulated sources with the flexibility needed to ensure adequate power supply.

Q. WHAT HAS BEEN THE RECENT EXPERIENCE WITH DEMAND RESPONSE PROGRAMS IN THE NORTHEAST?

A. New England, New York, and PJM put load reduction programs in place for the summer of 2001. The results are summarized in Attachment BEB-9. I believe that these programs demonstrate that demand response, including load reductions and use of back up generation, can be an effective and economical resource to use in meeting peak period loads.

Q. IS NPC'S SITUATION THE SAME AS THE SITUATION IN THE NORTHEAST?

A. NPC's situation is similar in some ways and different in others. The similarities include the need to address electric system peak period loads and peak prices, the technologies available to realize the reduction, and the concerns (e.g., environmental) that needed to be addressed. The differences include a different mix of customer types, end-uses, and the level of expected summer prices.

Other Issues and Conclusion

Q. DID NPC MAKE REASONABLE EFFORTS TO SELL ITS SURPLUS POWER?

A. NPC's procurement strategy was, by design, sure to lead to large amounts of surplus energy that could potentially be sold. This is particularly true for the last blocks of power added to the system. For example, in buying 6x16 product for Q3 to meet 66 hours of demand, there would be 1150 other hours in which the power could be sold. The sales of the surplus could take several different forms. There are shoulder hours with surplus on any given day. There are days with surplus during any month. And in a quarter there are lower load months, in which there could be surplus even on the monthly peak.

Selling the shoulder hours of a particular day is not difficult on an opportunity basis. These hourly non-firm sales, however, are not at high prices. Indeed, in the morning hours after the 6x16 blocks begin, NPC sold large amounts of "economy sales." The revenue from these sales was quite low. Cal-ISO actually had negative prices occasionally in these morning hours, meaning that due to surplus generation, that load was paid or credited, rather than charged for these hours.

Selling power that is not needed on a day-ahead or a few days ahead is another possibility. NPC could have had some success at this, but the summer 2001 prices were at levels that provided only partial recovery of the costs incurred by NPC to buy this power. For example, NPC's July 2001 on peak power was purchased at an average price of $225/MWh. The actual Palo Verde price in July averaged well under $100/MWh. So, while such sales can be made, the economics of those sales in this case was not attractive overall.

And finally, it is possible to sell monthly power for a particular month. NPC, for example, found itself with extra power for September as a result of the purchasing for products for the third quarter. July and August loads are significantly higher than September (see Attachment BEB-5).

Q. WOULD IT HAVE BEEN POSSIBLE FOR NPC TO SIMPLY PURCHASE LESS POWER FOR SEPTEMBER IN THE FIRST PLACE?

A. In theory, yes. However, according to NPC, monthly contracts are only rarely available in the broker market with long lead time. Rather, monthly contracts are "usually available only three to four months in advance" (Primer, page 51). Under this limitation, by the time that NPC would have been trading September power on a "normal" basis in the broker market, it would have been past the point at which prices had tumbled. This is another situation in which NPC's decision to rely almost entirely upon the "standard products" as traded in the broker market restricted the possibilities for procurement to better match its system needs.

Q. HOW DID THE PRICES THAT NPC PAID FOR PARTICULAR PRODUCTS COMPARE WITH THE "MARKET PRICES"?

A. The prices that NPC paid for any particular product in a particular time frame appear to be in line with listed market prices. I made comparisons and did not identify any problems with NPC's procurement in this regard.

Q. WAS NPC AWARE OF ITS EXPOSURE TO THE RISK OF FALLING PRICES?

A. From the materials that I have reviewed, it is unclear whether and to what extent NPC was aware of its exposure to falling prices. The Energy BookRunner software that the Company uses is capable of conducting various types of analysis of risk, including "stress testing" which could include evaluation of value-at-risk and earnings-at-risk. There is no evidence that the Company actually used these features, or that it seriously evaluated the possibility of falling market prices as it was accumulating its portfolio of contracts for summer power. While the Company understood that there was a possibility that prices might fall, it did little to evaluate that possibility or its implications for its power supply portfolio.

Q. HOW DID NPC FIGURE UNCERTAINTY INTO ITS PRICE FORECASTS?

A. It did not. NPC decisions were based upon forward prices from brokers, and uncertainty was not factored into its price forecasts (NPC's response to part G of Staff 82).

Q. PLEASE SUMMARIZE YOUR VIEW OF NPC'S PURCHASED POWER PROCUREMENT FOR THE SUMMER OF 2001?

A. NPC's approach was focused upon meeting the peak demands of the system with "standard products" that did not fit the system needs well. The large reliance upon 6x16 blocks caused problems with system dispatch, and created a tremendous surplus of energy in the non-peak hours. The Company's decision-making appears to be limited to comparisons of prices for traded products and not how to meet customer loads at a reasonable cost and risk exposure.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.