STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Tarrif Filing of Central Vermont	**)**	
Public Service Corporation Requesting	**)**	**Docket Nos. 6460 and 6120**
a 7.6% rate increase to take effect	**)**	
December 24, 2000	**)**	
Tarrif Filing of Central Vermont	**)**	
Public Service Corporation Requesting	**)**	
a 12.9% rate increase to take effect	**)**	
July 27, 1998	**)**	

SURREBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE VERMONT DEPARTMENT OF PUBLIC SERVICE

Resource Insight, Inc.

APRIL 20, 2001

TABLE OF CONTENTS

EXHIBITS

Exhibit DPS-PLC-S-1	*Excerpts from the Rebuttal Testimony of Paul Chernick, Docket Nos. 5270 CV 1&3 and 5686*
Exhibit DPS-PLC-S-2	*NEPOOL New Unit Adjustment Computations*

I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What is the subject of this surrebuttal testimony?

A: I respond to testimony of the Deehan-Cater-Amelang (DC&A) panel on the following six subjects:

- The externalities that should be attributed to the HQ-VJO contract.
- The treatment of risk proposed by DC&A.
- The arguments advanced by DC&A regarding the resources that would have replaced the HQ-VJO contract, had it been cancelled.
- A variety of suggestions from DC&A regarding the input values, such as costs, that should be used for determining the type of resource portfolio that Central Vermont might prudently have selected, following the cancellation of the HQ-VJO contract.
- Comments on DC&A's analytical errors.
- Whether any revision is necessary in my estimates of the rate-year damages due to the imprudent lock-in.

Q: What do you conclude regarding the issues raised by DC&A?

A: The major arguments advanced by DC&A, regarding externalities, risk, and resource selection are simply incorrect. So is their conclusion that CVPS might prudently have selected the HQ-VJO contract over the alternatives available in the early 1990s.

Some relatively minor points that DC&A make regarding early 1990s input values are correct, at least in part, but do not change my fundamental conclusions.

The panel's major claim regarding the estimation of actual damages in the rate years due to CVPS's imprudent lock-in is that various risk and externality adjustments should be made to the damages. None of DC&A's risk or externality adjustments are valid. In addition, in computing the cost of alternatives in the rate year, the panel unreasonably assumes that CVPS would have revived the Sheldon Springs project, even though less expensive alternatives were available.

Q: Do you have any other summary observations about DC&A's testimony?

A: I have four such observations.

First, DC&A rely in many places on materials, data and arguments presented by Green Mountain Power in Docket No. 5983 or 6107. The panel does not correct the errors in GMP's materials, even those that I explained in my rebuttal in those dockets.

The Board was not convinced by GMP's analyses in the GMP proceedings. It is not clear why DC&A believe that recycling GMP's assertions supports their analysis in this proceeding.

Second, some of DC&A's criticism of my direct testimony are based on CVPS documents that we did not find in the boxes of files made available on discovery in Docket No. 6018, and that CVPS had not provided in response to specific discovery.

Third, if there is continuing uncertainty regarding some inputs and assumptions, such as the sincerity of certain power-sales offers by Northeast Utilities, it is because CVPS did not aggressively seek less expensive alternatives to the HQ-VJO contract. The Company should not be allowed to hide behind uncertainties created by its own imprudence.

Fourth, DC&A focus (at 7) on "the alternative supplies (available at the time of the lock-in in 1991)," suggesting that they are relitigating the Board's finding of imprudence. As I explained in my direct testimony, this proceeding involves determining what would have happened following the VJO's refusal to lock into the HQ-VJO contract, had CVPS acted prudently.

II. Externalities

Q: What is the position of DC&A with regard to externalities and the valuation of the HQ-VJO contract?

A: The witnesses repeatedly insist that the HQ-VJO contract has environmental benefits, that those benefits should be valued using the externality values adopted by the Massachusetts DPU in 1991, and the resulting numerical values should be credited to the HQ-VJO contract for at least the following purposes:

- Determining whether Central Vermont might have prudently committed in 1992 to a purchase from HQ under pricing terms similar to the HQ-VJO contract.
- Estimating the economically used and useful portion of the contract.[1]

Q: Are the positions of the DC&A panel reasonable?

A: No, for two reasons. First, there are no environmental benefits from the HQ-VJO contract. Second, even if there were such benefits, there is no reason to

[1] I do not see any indication that DC&A intend that these values be used in determining the damages due to imprudence, but perhaps they mean that, as well.

believe that Central Vermont would have used the Massachusetts adders, or anything like them, to evaluate purchases from Hydro Québec in 1992. The purpose of my direct testimony on alternatives in the early 1990s was not an academic exercise, examining how someone might have compared the HQ-VJO contract to other resources, but an attempt to answer the historical question: what would CVPS have done, had it avoided the imprudent lock-in. While someone might have used the Massachusetts adders in comparing resource alternatives, the evidence all indicates that CVPS would not have done so.

A. The Lack of Environmental Benefits of the HQ-VJO Purchase

Q: Why do you say that there are no environmental benefits from the HQ-VJO contract?

A: I explained this point in some detail in my direct testimony. Mr. Biewald supplemented that explanation. Quite simply, the cancellation of the contract would have freed up about 2.2 million MWh/year of energy. Hydro Québec could have responded to the cancellation by deferring dam construction, making additional sales to some other utility in the northeast, reduced the generation from some Hydro Québec fossil plant (of which the existing heavy-oil-fired Tracy plant is the most likely candidate), or reduced purchases of fossil-fueled energy from elsewhere in the Northeast.

No one knows exactly what would have happened to the HQ-VJO energy, had the contract been cancelled, but these two things are clear:

- The energy would have gone somewhere, reducing environmental effects of some generating source.

- No party argues that the cancellation of the contract would have affected the timing of Hydro Québec's dam construction.[2]

As a result, the cancellation of the HQ-VJO contract would have reduced fossil-plant dispatch, and hence on air emissions, just about as much as CVPS's replacement resources would have increased them. In other words, the environmental effects of the HQ-VJO contract were essentially the same as for any other contract purchases from the market (regardless of how the sources are designated for billing purposes). In the 1990s, purchases from Hydro Québec or any other seller of existing or committed capacity would result in increased emissions from the existing fossil generation in the Northeast. After about 2000, those purchases would result in someone constructing and running new combined-cycle units; the emissions after 2000 would be roughly the same, regardless of whether CVPS purchased system power from a utility, purchased unit power from a new combined-cycle, or built new combined-cycle capacity itself.

Q: Where does CVPS express its agreement that the cancellation of the contract would not have affected the timing of Hydro Québec's dam construction?

A: In IR DPS 8-17, CVPS provides minutes that read, "...appear to indicate that the VJO contract was of minor importance in HQ's supply resource mix.... This suggests that the existence or absence of a 300 MW contract (VJO) wouldn't impact HQ's plans."

---

[2]Were CVPS to argue that the contract actually accelerated the construction of Hydro Québec's dams, it would need to monetize a range of other environmental effects, in addition to the air emissions from flooding the reservoirs.

Q: Did DC&A respond to your direct testimony, or that of Mr. Biewald?

A: No. DC&A fail to address any of our factual explanations, and resort to hand waving, claiming (at 22) that my testimony is "speculative" and (at 21) that Mr. Biewald's rests on "contemplation." They summarize (at 14–15)

> Contrary to the DPS assertions that environmental effects would not change in the region in total whether or not the VJO purchased HQ power, there is no factual record basis upon which to make that complex judgment.

I think that DC&A have this backward. Identifying the particular plants whose operation would have been reduced by cancellation of the HQ-VJO contract, or due to any sales contract involving existing or committed facilities would be a "complex judgment" that would require a "factual record."[3] The panel is correct that Mr. Biewald does not prove that the Tracy plant has run more due to the HQ-VJO contract, but neither of us purports to know exactly which fossil plants would have been run less due to cancellation.[4] The assertion that the HQ-VJO energy would have disappeared

---

[3]This analysis would be pointless, since the resources whose use was reduced by the cancellation of the HQ-VJO contract would be essentially the same as the resources whose use would have increased to serve the replacement purchase contracts, resulting in little or no net change in emissions, as Mr. Biewald and I pointed out in our direct.

[4]The objections that the panel actually raise to Mr. Biewald's suggestion that Tracy is probably running more due to the HQ-VJO contract are poorly founded. For example, DC&A suggest that Tracy might have operated to provide ancillary services ("VAR support or short-term operating stability") to the Montreal area. Since the transmission lines that serve the Highgate interconnection run from the Montreal area, it is not clear how support of the Montreal area is different from support for the sale. DC&A question whether "the Tracy oil-fired unit, in what is largely a hydro system,…is the marginal unit," even though the hydro energy is clearly not marginal. Similarly, they complain that Mr. Biewald "presents no information about scheduling of this unit's operation vs. the HQ/VJO purchase," even though scheduling is not relevant; Hydro Québec's large hydro storage capacity means that energy

in the absence of the contract (which is DC&A's implicit position) is an extraordinary assertion, which would require the support of an extraordinary evidentiary record.

The witnesses do not offer any plausible scenario in which the cancellation of the HQ-VJO contract would not have resulted in reduction of fossil-fueled emissions somewhere in the Northeast. I do not believe it was speculative for me to rely on the first law of thermodynamics (the conservation of energy), or Hydro Québec's desire to use its energy resources to maximize its export revenues, or the discovery responses of CVPS's witnesses.

Q: What environmental effects did DC&A attribute to the HQ-VJO purchase?

A: The panel (at 28–30) chose 0.21 pounds of CO_2 per kWh, citing the Board's order in 5330. That value is "associated with the development of hydro-electric facilities in the James Bay region" (Order in Docket No. 5330 at 182), expressed as equivalent pounds of carbon dioxide emitted due to the flooding of Hydro Québec reservoirs, per MWh of generation.

Q: Is this value relevant in any way?

A: No. The Board found, and CVPS's witnesses agree, that no additional hydroelectric facilities were developed (or expected in 1991 to be developed) due to the HQ-VJO contract.

---

generated by Tracy in one year can be stored as water behind a dam, and sold to CVPS years later.

B. How CVPS Would Have Valued Externalities in Resource Planning, Circa 1992

Q: Did Central Vermont use the Massachusetts adders in resource planning in 1991 or 1992?

A: No. Central Vermont has preferred to use "multi-attribute trade-off analysis" for environmental and other effects of its resource decisions. These multi-attribute analyses appear in CVPS's IRPs for 1991, 1994, and 1997.

Q: When did Central Vermont adopt monetized externality adders?

A: In December 1993, CVPS stipulated with the DPS on a set of externality adders, in Docket No. 5270-CV4. These values were considerably lower than the Massachusetts adders used in the DC&A testimony, as shown in the following table:

	CVPS 1993 1990 $/ton	**MDPU 1992** 1992 $/ton
SO_2	1,000	1,700
NOx	2,000	7,200
CO_2	15	24
CO	200	960
TSP	400	4,400
VOCs	1,500	5,900

In any case, CVPS continued concentrating on its multi-attribute trade-off analyses. By the time it prepared its 1997 avoided costs, CVPS had abandoned the stipulated externality values and returned to the placeholder 5% externality value of Docket No. 5270.

Central Vermont has never advocated the use of the Massachusetts adders for monetization of externalities, although it could easily have done so, particularly for DSM, and more generally in its IRPs.

Q: What is CVPS's basis for presenting an analysis of its potential decisions in 1991 or 1992, using techniques it did not endorse at the time?

A: The justification offered by DC&A (at note 20) is quite simple: "We maintain that since these adders were available in 1991, and Vermont had yet to develop anything comparable, it is reasonable to use these adders for this purpose." The justification has no bearing on the issues in this case, since it offers no evidence that Central Vermont would have used these adders. On discovery, DC&A refuse to state whether they are testifying that CVPS would actually have used the Massachusetts adders in 1991, and purport not to understand how CVPS's failure to use the adders in 1991 is relevant to DC&A's use of the adders in this proceeding (IR DPS 18-26).[5]

The question is not whether someone might have reasonably held a set of beliefs that would have led to a recommendation to sign a contract like the HQ-VJO purchase, but what CVPS would have done, had it avoided the imprudent lock-in and then acted prudently. As I explained in my direct testimony, this is a predictive exercise, relying primarily on the utility's own beliefs and practices.

Q: Might CVPS prudently have relied on the Massachusetts adders in 1991 or 1992?

A: I like to think that CVPS would have been prudent in 1991 to have hired me to advise it on resource planning, and I certainly would have suggested the

[5]To avoid answering a question about the prudence of its failure to use the Massachusetts adders "in 1991 and subsequent years," CVPS raises a spurious objection, pretending to believe that the question referred to the lock-in (for which "subsequent years" were not relevant).

use of the Massachusetts adders, some of which I developed.[6] CVPS itself clearly did not accept monetization of externalities, except as required to reach a stipulation with the Department, and abandoned monetization as soon as possible.

In 1991 or 1992, Central Vermont would not have used any monetized externalities.

Q: Is it possible to determine what weight a multi-attribute trade-off analysis would give to perceived environmental benefits of the HQ-VJO purchase?

A: No. The multi-attribute trade-off analyses CVPS presented in its IRPs provide no guidance in determining the weight that should be given to any non-price factor. These analyses simply display the tradeoffs, and leave to utility management the decisions of what options to select. DC&A could not "demonstrate that the multi-attribute analyses performed by CVPS would select the HQ-VJO purchase over the lower-cost alternatives" or even to establish "the numerical advantage that the multi-attribute analyses performed by CVPS would have given to the HQ-VJO purchase" (IR DPS 18-28, (b) and (c)).

Q: Has CVPS ever selected or recommended a higher-cost, lower-emission resource or portfolio, on the basis of its multi-attribute trade-off analyses?

[6] I also would have advised CVPS that the HQ-VJO purchase had no environmental benefits to monetize.

A: Not so far as I have been able to determine. In response to discovery, DC&A failed to identify "any CVPS multi-attribute analysis that selected more expensive resources to reduce environmental effects" (IR DPS 18-28a).

Q: How large is the externality adder that DC&A attribute to the HQ-VJO contract, as a percentage of direct avoided costs?

A: In Exhibit DCA-9, supposedly from a 1991 perspective, DC&A impute $133 million in net-present-value externality benefits, compared to a direct cost of $529 million, so the externality adder is 25%. In Exhibit DCA-9, from a current perspective, DC&A imputes externality benefits of $108 million, compared to direct costs of $380 million, for an externality adder of 28%.

In contrast, CVPS has generally acknowledged no more than a 5% externality adder for DSM. As I explained in my direct, extrapolating the DSM externality adder to the HQ-VJO contract, and recognizing that the Board found in Docket No. 5330 that most of the HQ-VJO energy would have been sold elsewhere, if not to Vermont, would imply an adder of less than 2% for the HQ-VJO contract. DC&A quote my conclusion, but do not rebut it.

Even if it had believed in 1991 that the HQ-VJO purchase would produce some environmental benefits, CVPS's estimates in this case of those benefits are greater than anything it was likely to have used at the time, by at least a factor of 10, and probably more.

Q: What do you conclude regarding DC&A's discussion of externalities?

A: The HQ-VJO contract had no environmental benefits to quantify. The Company did not use the externality values in the DC&A testimony in the early 1990s, and would not have used them to compare the HQ-VJO contract to alternatives. The Board should give no weight to DC&A's conclusions regarding externalities.

III. Risk

Q: How do DC&A model the risk-reduction benefits of the HQ-VJO contract?

A: The DC&A panel performs the following three analyses:

- Exhibit DCA-6 estimates the monthly standard deviation of the costs of three simplified portfolios: a 50:50 mix of Vermont Yankee and the HQ-VJO contract, a 50:50 mix of Vermont Yankee and an approximation of a gas combined-cycle plant, and 100% gas combined-cycle.
- Exhibit DCA-7 Attachment I values the HQ-VJO contract as though it were an option, using the Black-Scholes valuation model for financial options.
- Exhibit DCA-7 Attachment III attempts to use the Capital Asset Pricing Model to compute risk-adjusted discount rates and a "risk benefit" for the HQ-VJO contract, compared to a resource that varies with the quarterly price of gas.

Q: Are these analyses valid?

A: No. It is obvious that the price of the HQ-VJO contract varies less over time than do the prices of most alternative resources.[7] None of these analyses provide any useful valuation of that price stability.

[7]My direct testimony provides information on several other contracts signed in the early- to mid-1990s that provided similar price stability, at much lower cost.

Q: What problems have you identified in the DC&A risk analyses?

A: There are a number of problems with each analysis. In general, they use the wrong price data in inappropriate computations, and produce meaningless results.

Q: Did CVPS use any of these methods to make resource-planning decisions in the early 1990s?

A: No. So far as I can tell, CVPS previously proposed the use of risk-adjusted discount rates only in support of its attempt to eliminate fuel-switching as a DSM option, and has never proposed the use of the other techniques for any resource-planning purpose.

Q: Are the methods that DC&A proposes for measuring risk generally accepted for making decisions regarding energy procurement?

A: No. DC&A are not aware of any commercial applications of the methods they propose, for the purposes of corporations choosing between fixed and variable energy resources (IR DPS 19-50).

Q: Please describe the problems in Exhibit DCA-6's estimates of monthly standard deviations.

A: First, it is important to recognize that this methodology attempts only to measure variability, not to value variability. Second, the analysis is plagued with the following methodological problems that prevent it from accurately measuring the variability of CVPS's resource-portfolio cost, either including the HQ-VJO contract or alternatives:

- The model is highly oversimplified. All of CVPS's existing non-HQ resources are treated as being Vermont Yankee. After the retirement of

Vermont Yankee, all the non-HQ resources are treated as being gas combined-cycle plants.

- Deehan et al. treat all of CVPS's potential replacements for the HQ-VJO contract as gas-fired, even though a number of resources with different pricing provisions (fixed costs, or costs varying with various measures of inflation, gas, oil, or coal prices) were available in the early and middle 1990s.
- For some reason, DC&A used monthly data on prices. They do not specify why they believe monthly data add any real information. The HQ cost is set by year, not month; gas prices and electric market prices can be secured for more than a year with futures contracts, so no real monthly variation is necessary.[8] It is not clear that either CVPS investors or CVPS ratepayers care about the monthly fluctuations in fuel prices CVPS would pay, even if CVPS did not make its purchases on an annual basis. Since CVPS cannot normally change rates more than once a year, ratepayers would not see the monthly price variations.
- Actual monthly prices (or annual averages of those prices) vary from year to year due to, among other things, variation in weather and other short-term effects. If CVPS purchases fuel or electric energy in the futures market, or in short-term contracts, it can eliminate these short-term price fluctuations. DC&A's analysis should have used futures prices from the prior year or earlier, rather than spot prices that CVPS would never pay, especially if they were concerned about price stability.

[8]For purchases from gas-fired plants (such as QFs), CVPS would likely pay gas prices based on some rolling index, rather than current prices.

- Having used monthly data, DC&A eliminated certain months in which Vermont Yankee was out of service, on the grounds that such data "distorted the statistical covariance measures necessary to derive portfolio risk" (at footnote 20). Since the whole purpose of DC&A's analysis was to examine the variability in portfolio costs, and replacement power for Vermont Yankee is part of the portfolio, it is not clear why eliminating that portion of the portfolio would make any sense.
- The panel reflects variations in Vermont Yankee's average dollars per MWh due to fluctuations in capacity factor (other than the months with complete or near-complete scheduled outages), However, they do not reflect monthly variations in Hydro Québec prices due to fluctuations in capacity factor. This treatment understates the variability in Hydro Québec prices.

Even were these inconsistencies corrected, the analysis provides no valuation. For that reason, it is not clear that the portfolio analysis conducted by DC&A in Exhibit DCA-6 could ever provide any useful information.

Q: Please describe the problems in the options valuation in Exhibit DCA-7 Attachment I.

A: The most basic problem with the options approach is that the HQ-VJO contract is not an option. Exhibit DCA-7 Attachment I would be relevant to determining the value of a contract in which Hydro Québec gave CVPS the option at the beginning of each year, once the actual market price of power was known, to take the HQ-VJO power in that year, at the contract price, and otherwise neither take nor pay for the power. The analysis essentially computes the probability that market prices would exceed the HQ-VJO price in any given year (let's call that *p),* multiplies that by the expected difference *(d)* between market price and HQ-VJO price, and computes the present value of the annual $p \times d$ over the remaining years of the contract. DC&A, in their analysis, find that such an option would be worth $43 million.

But CVPS cannot decline the HQ-VJO contract power and charges. The contract is take-or-pay, not an option. In addition to the benefits when market price exceeds the annual HQ-VJO price (an event that does not seem to have occurred, and is not projected to occur in any forecast in this proceeding), CVPS gets the costs when the HQ-VJO price is higher than market price. So this entire analysis is nonsense.

Q: What is DC&A's defense of computing the value of the HQ-VJO contract as if it were an option?

A: Basically, they claim that in computing an option value for a contract with no options, they are not treating it as an option. In other words, they simply assert that they are not doing what they are obviously doing. Their clearest justification is:

> Messrs. Biewald and Chernick have estimated potential losses associated with the contract but they have made no attempt to estimate potential gains. This is not intellectually honest because it tells only half the story. Since the option pricing techniques measure potential gains, the values they give rise to can be used to balance the potential losses emphasized by the DPS's witnesses. (Exhibit DCA-7 at 2)

In fact, Mr. Biewald and I provide a balanced perspective, using expected costs that reflect the average of higher potential losses, lower potential losses and even (under some unlikely circumstances) small potential gains from the contract. The option value that DC&A compute for the contract as a call held by CVPS reflects only the potential gains. DC&A essentially add the potential benefit to the expected value, producing a badly overstated estimate of the contract's value.

If DC&A wanted to include the value of the contract as a call option for CVPS, they should also recognize the much larger value of the contract as a put option for Hydro Québec, which Hydro Québec would have exercised every year to date, and which Hydro Québec is likely to exercise every year in the future. Starting with DC&A's estimate of the call value as $43 million and their interpretation of the asset price (the discounted value of the market price) and strike price (the discounted contract price) for the HQ-VJO contract, and applying the put-call parity formula (the value of the put equals the value of the call plus the strike price, minus the asset price), I get a put value of $288 million. Subtracting the $43 million in potential benefit from the $288 million in potential costs leaves CVPS worse off by $245 million.[9]

Q: Did DC&A properly model the benefit of an option to take HQ-VJO contract power, had one been offered?

A: No. The errors in DC&A's options analysis (other than the fact that they did it) include the following:

- Deehan et al. assume that Central Vermont's alternative to HQ was to play the spot market on an annual basis, and that the entire market price would vary with the price of gas delivered to utilities. In fact, most of Central Vermont's power would almost certainly have been purchased through contracts with some fixed charges. Only a portion of the cost of power would vary with fuel prices.
- DC&A used a nationwide average price of gas delivered to electric utilities nationwide, rather than a value for New England or any other

[9]This computation, following DC&A, uses a risk-free discount rate, and may overstate the expected cost of the contract as the Board would normally compute it.

fixed reference. Over time, the mix of gas purchased by electric utilities has varied geographically (with lots of gas-fired generation in the Southwest in the beginning and increasing amounts in the Northeast and Midwest over time), seasonally (with gas burned mostly in the summer in some years, and year-round in others) and contractually (with varying mixes of firm and interruptible supply). So the data that DC&A use vary in ways that have nothing to do with the cost of gas for firm supplies to New England generators.

- The data period DC&A selected includes the increases in gas prices as wellhead gas-price regulation distorted the market in the late 1970s and early 1980s, and the collapse in price after deregulation in 1984 as lock-in gas was released onto the market. If we look at the post-deregulation period (1986–1999), the standard deviation is only 11.7% of the average price, not the 30% DC&A compute for the longer, less-relevant period.
- Deehan et al. compute the "volatility" parameter for their calculation as the ratio of standard deviation to mean of their 24 annual gas prices (1976–1999). There is no time dimension in this computation; DC&A just took the average of the 24 prices and computed variance and standard deviation from that mean. But in the Black-Scholes formula, the volatility measure is standard deviation in the annual *change* in price of the asset for which an option is being purchased. In DC&A's application, that would be the standard deviation of the *change* in market prices (or the price of gas, as a proxy), not the standard deviation of the *prices*. Again, DC&A's analysis is inconsistent with the underlying theory.
- The Black-Scholes formula assumes a log-normal distribution of prices for the asset. In a log-normal distribution, an increase of 100% is as

likely as a decrease of 50%. Hence, the average price in a log-normal distribution is higher than the central value, or mode. It appears that DC&A have assumed that the expected values of future market prices will be greater than the projections that they purport to be using.

- The panelists appear to have made some mathematical errors in their application of the common-stock option valuation form of the Black-Scholes formula to valuing an option on a commodity (electric) future. In the d_1 and d_2 probability parameters described in Exhibit DCA-7, DC&A discounted the future price of power before computing the term *LN(future price/strike price).* They offer no explanation for this discounting, and I do not find any reference to such discounting in the finance texts I have consulted. In addition, in computing the d_1 and d_2 probability parameters, DC&A include a $r \times t$ term (risk-free discount rate times time), which is not included in Black's version of the formula for commodity options.
- The Black-Scholes formula assumes that the uncertainty in future asset prices increases as the square root of the number of years into the future that option can be exercised. DC&A assume an annual volatility of 30%, which means that the variability by the last year of the analysis is 116% of the expected price. Future market prices are uncertain, but the uncertainty does not grow in the regular fashion over time. Many factors (extreme weather, demand growth) can drive up prices in the short run, but those increases tend to be self-correcting over time, as weather patterns average out and new capacity is added.[10] So the Black-

[10] The panelists seem to acknowledge this, by estimating the volatility parameter as the standard deviation of all historical prices, without any attention to annual changes.

Scholes treatment of asset price variation, which may be appropriate for stocks, is unlikely to match well the actual patterns of price changes in gas or electricity.

Q: Please describe the problems in the Capital Asset Pricing Model analysis in Exhibit DCA-7 Attachment III.

A: The panel's application of the Capital Asset Pricing Model (CAPM) is largely a rehash of the application of the same model by Shimon Awerbuch, in his rebuttal testimony for CVPS in Dockets Nos. 5270-CV-1, 5270-CV-3, and 5686, in 1994. My rebuttal testimony explained Dr. Awerbuch's errors, which DC&A have generally repeated.

I have attached the relevant portion of that earlier testimony in the earlier proceeding, as Exhibit DPS-PLC-S-1. To summarize a few of the high points, the DC&A analysis

- incorrectly measures the cost of power to customers, confusing an increase in prices with high prices. I doubt that consumers care much whether their bills have gone up or down from the previous year; I would expect that they care about the absolute level of the bills. Yet DC&A count prices as "bad" when they rise, even if the price is low before and after the increase, and "good" when they fall, even if the price is high both before and after the change.[11]

---

[11]For example, EIA reports that the average residential price of home heating oil fell from $1.51/gallon in 1981 to $1.38 in 1982, and rose from $0.78/gallon in 1988 to $0.83 in 1989 (all in 1987 dollars). DC&A's approach to CAPM would treat 1982 as a "good" year for consumers in terms of oil prices, and 1989 as a "bad" year, even though prices were much lower in 1989.

Ironically, DC&A get their measures of fuel price volatility backwards between two analyses. In the options analysis, in which volatility must mean "annual change," DC&A use

- assumes that the welfare of energy consumers in Vermont is tied to total return on the Standard and Poor's 500 stock index, rather than to more realistic measures, such as Vermont per-capita income. DC&A define risk in this analysis essentially as the probability that energy prices will rise when the S&P 500 falls. It is likely that most CVPS customers worry more about prices rising when they are out of a job, or otherwise under financial stress. DC&A did not measure the correlation of energy prices with any real measures of Vermont's economic welfare.
- assumes that market commodity prices are free to wander at random for many years, without any market pressures to bring them back to long-term incremental costs.

Q: When you corrected CVPS's errors in the 1994 testimony, did the result vary significantly from those of CVPS?

A: Yes. Awerbuch, like DC&A, found that changes in fossil fuel prices were negatively correlated with the return on the S&P 500, and concluded that fuel added to customers' total risk: a year with rising fuel prices would also be likely to be a year with falling (or at best anemic) stock prices, making a bad situation worse. When I corrected the data, using Vermont income rather than the largely irrelevant S&P 500 and using actual values, rather than annual changes, I found the opposite: fuel prices tended to be high when Vermont's

---

prices, rather than change in prices. In the CAPM analysis, in which fuel price, not change in price, should be important, they use the change in price.

economy was robust, and lower when the economy was soft. Fuel prices moved counter-cyclically, cushioning the economic cycle.[12]

Q: Are there any other problems in DC&A's CAPM analysis, beyond those that DC&A repeat from the 1994 case?

A: Yes.

- The panelists use gas prices at Henry Hub (in Louisiana) as a proxy for market prices in New England. Henry Hub gas prices may affect the New England electricity market, but so do many other factors. Henry Hub gas prices are unlikely to mirror closely New England electricity prices.
- As in the portfolio-variability analysis, DC&A use monthly price data. All the same problems arise with the use of monthly data here as in the earlier analysis.
- Gas prices (which DC&A use as a proxy for electric market prices) vary seasonally, traditionally with a strong winter peak. Electric market prices, on the other hand, are generally greater in the summer. It is not clear why DC&A chose to use seasonal data and to model market electric prices with a proxy that moves in the opposite seasonal pattern from electric market prices.
- Even though DC&A report monthly prices for the HQ-VJO contract in dollars per MWh, they actually use an annual average, rather than the monthly values. Since the capacity charges are fixed, and energy take varies, the actual price of HQ-VJO power varies monthly. If monthly

[12]That makes some sense. For example, in a recession, electric and gas prices on the wholesale market are apt to fall with falling demand. Of course, Vermont's economic activity does not necessarily move exactly with that of the region or the nation.

price volatility matters, DC&A should have reflected the variation in monthly HQ costs. If not (as I believe), DC&A should not have included monthly variation in gas prices.

- Even though DC&A present ten years of data, they throw out the first half, and only use five years of data. They do not explain why.

Most fundamentally, DC&A introduce a novel concept into the CAPM: a lag between two correlated variables. The CAPM is intended to measure the extent to which the return on an asset is correlated with a broader portfolio. If the addition of the asset makes the portfolio more volatile, the investor will be even worse off in bad periods if he adds some of the asset to his portfolio. Nothing in the CAPM is concerned with whether a good period for an asset is followed some time later by a bad period for the portfolio. The CAPM only measures the risk of simultaneous poor performance.

DC&A find that the beta (the measure of correlation) between changes in the price of gas at Henry Hub and the returns on the S&P 500 in the same month are positively correlated. If DC&A had accepted this conclusion, they would have modeled gas (and hence market purchases) as having a "good" risk, moderating volatility in investment returns, and would have discounted the costs of market purchases at a higher discount rate than they use for the HQ-VJO contract. So DC&A also compute the betas with the S&P 500 return lagged by 1, 2, 3, and 4 months, and use the average beta in their CAPM computation. They offer no rationale for this unorthodox procedure.

The extreme sensitivities of the betas to the choice of the lag demonstrates how arbitrary and contrived DC&A's CAPM analysis is.

IV. Replacement Resources for the HQ-VJO Contract

Q: What issues do DC&A raise regarding the resources that CVPS would have considered to be alternatives to the HQ-VJO contract?

A: I have identified the following five such issues:[13]

- Whether CVPS would have considered additional DSM in the replacement portfolio (at 56).
- Whether the system-power offer from NU should be included in the resource mix (at 56).
- Whether the Sheldon Springs (or Bonneville) project would have been revived by the cancellation of the HQ-VJO contract (at 55, 73–74).
- Whether Sheldon Springs, had it been revived, should have been treated as coming on line in 1994 (at 74).
- Whether additional high-priced QFs would have been approved by the Board and licensed had the HQ-VJO contract been cancelled (at 68–69).
- Whether DC&A are reasonable in adding 60 MW of a Sheldon Springs "clone" (using DC&A's terminology) in 1998 (at 73–74).

A. Demand-Side Management

Q: Are DC&A correct about your omission of DSM?

A: Yes. I was aware when I prepared my direct that cancellation of the HQ-VJO contract might result in the implementation of more cost-effective DSM, but

---

[13]In their testimony at 55, DC&A assert that the replacement portfolios that I use are inappropriate because I ignore *four* conditions from the early 1990s, but they list only three such conditions, which are the first three items in my list. The other three items in my list are drawn from other places in their testimony.

I did not estimate the quantity and cost. Adding cost-effective DSM would further reduce the cost of the alternative to the HQ-VJO contract.

I am surprised that DC&A admit (indeed, volunteer) that the lock-in of the HQ-VJO contract resulted in the elimination of cost-effective DSM from CVPS's portfolio. This appears to be admission that CVPS knew, or should have known, in 1991 that it was violating Condition 8 of the Board's Order in Docket No. 5330 by agreeing to the lock-in.

Q: Have DC&A correctly estimated the cost of DSM?

A: No. They failed to credit the DSM with its benefits in avoiding transmission and distribution costs (IR DPS 19-3(g)). Using a moderate estimate of avoided T&D costs, of $100/kW-yr in 1996 dollars, I estimate that the T&D benefits would cover about $850/kW of investment, or nearly half the cost that DC&A estimate for their DSM program. This correction would reduce the present-value cost of DC&A's non-HQ portfolio by $40 million, two-thirds of the advantage DC&A claim for the HQ-VJO contract over their (woefully inefficient) non-HQ portfolio.

Q: Have DC&A correctly estimated the potential effect of DSM on the non-HQ portfolio?

A: I have not independently evaluated DC&A's unsupported opinion that 5 MW of DSM over 5 years was "a reasonable amount of expected additional DSM" (IR DPS 19-3 (h) and (i)). However, I do believe that DC&A erred in assuming that the DSM would disappear after 12 years. As they acknowledge, "In reality, CVPS would have expected the end user or ongoing programs to replace the measures in kind" (IR DPS 19-3 (l)).[14] In DC&A's portfolio, the elimination of the DSM results in the addition of combustion turbines, which operate at capacity factors of as much as 27%. Had DC&A properly modeled the continuation of the DSM load reductions, this expensive use of combustion turbines would have been avoided.

B. Northeast Utilities' System Proposal

Q: What is DC&A's point regarding NU's system proposal?

A: They assert (at 55) that the offer from NU to provide system power was a "dead-end draft proposal," and (at 56) that I "assume" that the NU system proposal was a "final offer."

Q: What is the basis for DC&A's claim that you assume that the NU system-power option was a final offer?

A: The basis for DC&A's claim is not entirely clear. DC&A appear to take the position that only signed, firm contracts can be taken seriously for resource-planning purposes and for assessing damages due to imprudence. Since CVPS never sought a firm commitment from alternative suppliers, no one can prove that those suppliers would have actually signed such commitments Therefore, in DC&A's view, I *must* be assuming that the NU system-power option was a final offer.

Q: Do you believe that the replacement portfolio should be limited to final contract offers?

---

[14]Since the measures had already been installed once, subsequent replacements would likely have been less expensive, and user-implemented replacements would not incur program overheads, so the extended DSM might well have been less expensive than the initial installations.

A: No. DC&A's argument contradicts the position taken by CVPS prior to the lock-in and in Docket No. 5701. CVPS justified its commitment to the HQ-VJO contract based on analyses of replacement portfolios that included the NU's Oil Block option, also a draft proposal provided to CVPS in the same transmittal, which DC&A describe as a "single, illegible set of faxed tables marked as a draft proposal, with no accompanying explanatory text."

Q: What is the basis for DC&A's claim that NU system power was a dead-end proposal?

A: Deehan et al. make the following assertions:

- A letter from Mr. Schaeffer to NU requesting further explanation of NU's offers never received a response (at 57).
- The capacity and energy charges under NU's system-power option are round numbers, not the proposal NU would have presented if it had "spent time developing what it intended to be a firm or binding offer…." (at 57, footnote 30).
- There is an inconsistency between NU's system-power and winter-baseload–summer-peaking options that indicates that the $.02/kWh energy charge must have either been a mistake or based on the mistaken expectation that CV would not purchase power in the summer (at 56–57).

Q: Does the use of round numbers indicate that the offer to sell is not a genuine proposal?

A: No. In the early 1990s, NU signed a number of firm and binding contracts that include prices that are round numbers. Several of these are listed in my Exhibit PLC-9. For example,

- All of the prices in all years—for energy, as well as for separate base, intermediate and peaking capacity—in NU's contracts with Danvers and Littleton are multiples of either $5/MWh or $5/kW-yr.
- The NU contracts with Princeton and Madison have capacity prices that are all divisible by $5/kW-yr.[15]

Later signed contracts (provided in my direct exhibits) have similarly round numbers, as follows:

- NU's contract with BED contains capacity charges of $50/kW-yr in 1998, increasing by $5 or $10/kW-yr annually, to $120/kW-yr in 2007, and energy prices of $25.00/MWh on-peak and $20.50/MWh off-peak, both increasing by exactly $1.50/MWh each year.
- Central Vermont's own contract for sales to the NHEC provides for a base energy charge of $18/MWh and an incremental capacity rate of $18/kW-yr, both escalating with inflation.

Other utilities also made offers in the early 1990s using round numbers.[16] DC&A's assertion (at footnote 30) that firm or binding offers do not have round price values simply has no basis in fact.

Q: Do you agree that comparison of the system-power option with the Summer-Winter mix indicates that the system-power option is a mistake?

---

[15]In the case of the Princeton contract, the energy prices are a pass-through of the actual fuel costs of the units specified, while the Madison energy prices are pre-determined whole-dollar-per-kW-yr. amounts that vary from year to year over the life of the contract.

[16]For example, Niagara Mohawk's Proposal A included a capacity cost of $60/kW-yr and an energy adder of $3/MWh. NYSEG's Proposal A included a capacity cost of $3.50/kW-month and an energy charge of $31/MWh.

A: No. The System-Power option is perfectly consistent with the Oil Block option. System Power is baseload option, while the Oil Block is a peaking-to-intermediate option. It is more expensive than the Oil Block at capacity factors less . than 40%.

If any of the three options is odd or unsuitable for the CVPS system, it is the Summer/Winter mix.

Q: Do you agree that Mr. Schaeffer's letter to NU demonstrates that NU's system-power option was a dead-end draft proposal?

A: No. Mr. Schaeffer did not question whether NU meant to propose a $20/MWh system-power energy charge. His questions were more specific: whether the $20/MWh was a fixed number, or an estimate or the result of a computation, and exactly how it would inflate. Indeed, his letter appears to accept the sincerity of the offer.

Mr. Schaeffer's letter is more an indication of CVPS's lack of interest in developing feasible alternatives to the HQ-VJO contract than it is evidence that the NU system-power option was a dead-end proposal. Even though NU had sent its draft proposals to CVPS in February 1991, Mr. Schaeffer's letter requesting further information was not sent out until August 28, 1991, the day of the HQ-VJO lock-in. At that point NU must have known that it would not be selling much power to CVPS.

Q: If NU's system offer were considered too difficult to interpret, would DC&A's substitution of NU's oil block be the most reasonable alternative?

A: No. The workpapers provided by DC&A themselves show that a portfolio including NYSEG's Offer A rather than the Oil Block, but otherwise similar to the portfolio in their Exhibit 9, was less expensive than the alternative portfolio they propose in Exhibit 9 and slightly less expensive than the HQ-VJO contract. This is true despite the inclusion of the early and uneconomic Sheldon Springs (and Sheldon Springs "clone") capacity, and the analytical errors I discuss in §VI.

Q: Do DC&A offer any rationale for presenting the Board with a portfolio including the NU Oil Block, rather than the less expensive NYSEG offer?

A: The only rationale that DC&A offer is that the "NYSEG A purchase was not available as an option until April 23, 1992" (IR DPS 19-1). DC&A appear to be shifting the analysis back to the period of the lock-in, which the Board has already found imprudent, and attempting to relitigate that precluded issue. For the purpose of this proceeding, the issue is what CVPS would have done following the lock-in date. DC&A have not offered any rationale for ignoring resources offered to CVPS in 1992.

The Board has previously found in Docket No. 5983 that the Vermont Joint Owners would have canceled the contract sometime in 1992, as the contract's economics continued to deteriorate (Docket No. 5983, Order at 240). The critical analyses that would have led to the final cancellation of the HQ-VJO contract might well have occurred in 1992, rather than in 1991.

C. Sheldon Springs Completion and Timing

Q: What is the basis for DC&A's assertion that cancellation of the HQ-VJO contract would have resulted in the completion of the Sheldon Springs project?

A: Since CVPS had signed a contract with Bonneville, DC&A argue (at 55, 73–74) that the utility would likely have been obligated to purchase Sheldon Springs power.

Q: Do you believe that CVPS would have had to purchase Sheldon Springs power if the HQ-VJO contract had been cancelled?

A: No, for the following reasons:

- It appears unlikely that the Sheldon Springs project would have been completed even if the HQ-VJO contract had been cancelled.
- The Bonneville contract did not necessarily obligate CVPS to purchase power from Sheldon Springs.
- Central Vermont did not believe at the time that it would have to purchase power from Sheldon Springs if it backed out of the HQ-VJO contract.

Q: Why is it unlikely that the Sheldon Springs project would have been completed even had the HQ-VJO contract been canceled?

A: For the following reasons:

- If the HQ-VJO contract had been cancelled, it is unlikely that the Board would have approved the early Sheldon Springs purchase when a less-costly resource—the HQ-VJO contract—had just been cancelled.
- By 1991, CVPS had decided not to actively support the project before the Board, because in its view the plant was unneeded and uneconomic.
- New England had excess capacity for several years with or without the HQ-VJO contract, at prices less than the Sheldon Springs purchase.

Q: What is the basis for your statement that CVPS had decided not to support the project?

A: According to the testimony of the Energy Management Associates in Docket No. 5724 (at 100),

> In October 1990, CVPS concluded from its studies, which incorporated changing market conditions, that there were now significant questions regarding the need and economics of the project–the two issues for which CVPS was responsible in the Section 248 proceeding before the Board. CVPS immediately informed Bonneville Pacific that it could not support the project at that time. Bonneville Pacific elected not to proceed further without CVPS'[s] active support and withdrew its application for the Certificate of Public Good. The Board closed the docket in December 1992. Although the outcome of this competitive bidding process did not produce new capacity, it did demonstrate CVPS's efforts to closely monitor changing market conditions and adapt Company actions accordingly.

Q: What limited CVPS's contractual commitment to the Sheldon Springs project?

A: It appears that the contract did not require CVPS to support the project before the Board's proceedings on the State Certificate of Public Good if it were unneeded and uneconomic.

Q: In 1991, did CVPS assume that it would have to purchase Sheldon Springs power if it cancelled the HQ-VJO contract?

A: No. In its 1991 HQ analyses, CVPS included the Sheldon Springs project in only some, not all, of the replacement-resource portfolios. In addition, by the time the September 1991 IRP was prepared, Bonneville Pacific had notified CVPS of its intent to withdraw its application for a Certificate of Public Good (September 1991 IRP at IIIC-21).

Q: If Sheldon Springs had been revived, when might it have been completed?

A: In one of the cases analyzed in CVPS's April 1991 HQ study (the only case for which the CVPS documentation provides this information), Sheldon Springs would have come on-line in October 1995 (Exhibit EMA R-1 at 220, 272). This is almost two years after the completion date that DC&A assume.

D. Cancellation of the HQ-VJO Contract and Completion of Expensive QFs

Q: What is the basis for DC&A's assertion that cancellation of the HQ-VJO contract would have resulted in the completion of three NUGs in addition to Sheldon Springs?

A: Deehan et al. contend that the three NUGs, which were abandoned due to lack of need, might have been built had the HQ-VJO contract been cancelled, at rates lower than originally proposed but higher than HQ-VJO contract.

Q: Is DC&A's argument valid?

A: No. It is unlikely that the Board would have approved a resource at a price more costly than the HQ-VJO contract, if the latter had just been cancelled because it was uneconomic. DC&A's testimony explains how the East Georgia QF was rejected by the Board due to lack of need and excessive costs. It is hard to see how cancellation of the HQ-VJO contract on economic grounds could justify approval of more-expensive resources.

E. The 1998 Sheldon Springs Clone

Q: Were DC&A reasonable in assuming that CVPS would replace the HQ-VJO contract, in part, with a NUG similar to Sheldon Springs in 1998?

A: No. The so-called Sheldon Springs clone is significantly more expensive in 1998 than the purchase options available in the early 1990s.

Q: What justification do DC&A give for including this expensive resource?

A: They do not offer any justification for assuming the purchase of power from a new resource, rather than from the excess capacity available in the market. They do argue that Sheldon Springs was a low-cost NUG, and a reasonable basis for projecting the cost of CVPS's future purchases from new combined-cycle units. I agree with that characterization. Indeed, I used a deferred Sheldon Springs to estimate the costs of a new combined-cycle in 2006.

V. Input Assumptions

Q: About which input assumptions do you and DC&A disagree?

A: Their complaints include the claims that my analysis

- overstated the cost of the HQ-VJO contract, from a 1991 perspective (at 60–61).
- ended Schedule C-4a in 2012 when it actually extends to 2016. DC&A conclude that my calculations understated the capacity of the HQ contract in the later years when HQ finally provides positive net benefits (at 61).
- ignored the banking benefits of Sellback 2 (at 61).
- ignored the additional capacity benefits of the HQ-VJO contract due to the NEPOOL New Unit Adjustment (NUA) (at 60–61).
- understated the heat rate for a new utility-owned combined-cycle. In DC&A's view, CVPS's assumption reasonably reflects actual operating conditions and falls below the actual or projected heat rates of four New England projects (at 65–66).
- understated the combined-cycle capital cost (at 63–64).

- improperly relied on the NEPOOL GTF's estimate of the "cost of transporting gas from the United States Gulf Coast" even though "most combined-cycle units proposed in 1991 in New England were expecting to purchase gas from Canada, which had higher pipeline costs" (at 62–63).
- ignored additional NEP or PSNH wheeling that DC&A assert NU power purchases would have required (at 59).

The below sections discuss in turn DC&A's three complaints about my treatment of the HQ-VJO contract, their complaints about my treatment of new gas combined-cycle units, and their one claim about wheeling charges for NU purchases.

A. Costs and Benefits of the Hydro Québec–Vermont Joint Owner Contract

Q: What is the basis for DC&A's claim that your analysis overstates the cost of HQ that CVPS projected in 1991?

A: According to DC&A at 60, CVPS's July 1991 estimates of HQ capacity costs (which I used in my calculations) did not reflect reductions in interest-rate, Handy-Whitman, and inflation indices that were available to CVPS in 1991. In addition, DC&A claim that CVPS's July 1991 energy-price projections did not reflect "more detailed" calculations using lower inflation forecasts. DC&A claim that I have overstated HQ-VJO contract capacity costs by about 2% and energy costs by about 3%, resulting in an overall error of $16 million.

Q: Does DC&A's revision necessarily reflect the projection of HQ-VJO contract costs that CVPS would have relied on in late 1991?

A: No. DC&A's adjustment to the forecast of HQ-VJO contract costs is a reconstruction of a complex calculation based on data and projections available in 1991. DC&A provide no verification that CVPS actually relied on or would have relied on this revised cost projection. They show only that CVPS *could* have recalculated its HQ-VJO contract cost projections based on these inputs.

My analysis used the then most up-to-date CVPS projection that I could locate in the boxes of material CVPS provided. In response to my request for the HQ-VJO contract cost projections used by CVPS in its October 1991 analysis of sell-back options, I was directed the materials already provided. As far as I can determine, the July 1991 figures represent CVPS's estimate of HQ-VJO contract costs at the end of 1991. DC&A's testimony provides no information to the contrary.

Q: Was it inappropriate for you to assume that Schedule C-4a ends in 2012, even though DC&A testify that Schedule C-4a extends to 2016?

A: No. The 1991 CVPS documents that I rely on indicated that at the time, CVPS assumed that Schedule C4 would end in 2012. The following documents describe Schedule C4 as ending in 2012:

- The April 1991 HQ-VJO contract study (provided in Exhibit EMA R-1 in Docket No. 5701);
- The October 1991 sellback study (provided in Exhibit EMA R-1 in Docket No. 5701);
- CVPS's September 1991 IRP, Section VI.A.1, in the text at VI-3 and in a table at VI-4;
- Exhibit EMA-18 at 5 (Docket No. 5701).

Whatever CVPS believes now, it clearly believed in 1991 that Schedule C4 ended in 2012, and told its EMA witnesses as much in 1994.

Q: Did you err in omitting the New Unit Adjustment for the HQ-VJO purchase?

A: I did make a mistake here. However, the effect is not as important as DC&A contend, for two reasons.

First, there would be an offsetting NUA adjustment for new combined-cycle and combustion turbines, which DC&A include in their portfolio, as well as for system purchases from outside the region, such as NYSEG's offer. NEPOOL's NUA provided extra capacity credits for any resources that were smaller and more reliable than the average of the existing NEPOOL stock. Sheldon Springs, with its small units (31 MW for Unit 1 and 21 MW for Unit 2) and high reliability, would receive a significant NUA credit. For example, NEPOOL expected the 37-MW Pepperell NUG to have a 2% credit in the winter and 12% in the summer (or an average of 7%). Purchases from New York utilities (other than those with large seasonal deratings) were given larger NUA credits than were the HQ-VJO schedules, as shown for various NiMo (or "NM") and NYPA contracts in Exhibit DPS-PLC-S-2.[17]

Second, DC&A seem to have overstated the magnitude of the NUA on the capacity credit for the HQ-VJO contract. In their workpapers, DC&A provide a few pages from NEPOOL's Criteria, Rules and Standards No. 37, "New Units in Capability Responsibility," which laid out the NUA formula. However, DC&A do not include the pages of that document that present

[17]The workpapers provided by DC&A include an excerpt from NEPOOL's GTF report showing New York purchases with better reliability than the HQ-VJO purchases over either Highgate or the NEPOOL-HQ interconnection.

NEPOOL's computation of expected NUA for planned resources, including the early schedules of the HQ-VJO contract. These examples evaluate each Schedule of the HQ-VJO contract as a single resource, while DC&A treat CVPS's share of each schedule as a separate resource.[18] As a result NEPOOL's calculations from various periods (I provide examples from 1989, 1993, and 1994 in Exhibit DPS-PLC-S-2) suggest NUA credits for various HQ-VJO Schedules of 14–15% in the summer and 8–13% in the winter, for an average of 10–14%, rather than the 20% DC&A claim.

B. Inputs for Gas Combined-Cycle Units

Q: What inputs do DC&A raise questions about?

A: They take exception with my testimony on combined-cycle heat rate, capital cost, and pipeline transportation charges.

Q: What is the significance of these disputes?

A: Not much. Both DC&A and I use the costs of Sheldon Springs as a proxy for the cost of later combined-cycle plants. As I said in my direct at 22, "With CVPS's cost assumptions, the least-cost option would have been a NUG purchase, at the cost of Sheldon Springs….Cost inputs more realistic than those used by CVPS would result in similar costs for utility-owned and NUG units." I made the point that CVPS's assumed costs for new utility baseload

[18] It is difficult to see how NEPOOL could treat the HQ-VJO contract in this manner, since (1) NEPOOL treated all of Vermont as a single participant and (2) the HQ-VJO contract is a single contract, not a series of separate contracts with each of the VJO participants. VELCo's rules for allocating the Vermont reserve requirements among the Vermont utilities may give CVPS some additional credit, but at the expense of utilities that did not buy into the HQ-VJO contract.

combined-cycle plants biased its 1991 analyses toward the HQ-VJO contract. As I told the Board in my direct testimony those assumptions should not be used in determining CVPS's prudent portfolio had it avoided the HQ-VJO lock-in. DC&A essentially accept my position by using NUG costs rather than CVPS's inflated combined-cycle costs.

1. Heat Rate

Q: Does DC&A's testimony provide adequate support for the high combined-cycle heat rates that CVPS used in its 1991 analyses?

A: No, for two reasons.

First, DC&A misrepresent what CVPS assumed about heat rates. DC&A claim (at 65) that "[t]he CVPS assumption for combined-cycle unit heat rate represents a long range, annual average, which reflects a number of effects of operations (sic) conditions.…Applying a factor of 1.06 to a full-load heat rate of 8,400 BTU/kWh, provides the 8,900 long term annual average heat rate used by CVPS in 1991 and in this testimony." Had CVPS done what DC&A claims, it would have been consistent in using the 8,400 BTU/kWh full-load heat rate from the NEPOOL GTF, modified for cycling and other seasonal variations. In fact, CVPS's UPLAN runs used the 8,900 BTU/kWh as the combined-cycle units' full load heat rate and specified higher values for part-load operation, resulting in an average annual heat rate of 9,430 BTU/kWh (UPLAN files in Exhibit EMA R-1 at 253).[19]

---

[19]Interestingly, the UPLAN runs show a 6% difference between annual and full-load heat rates. DC&A claim that CVPS increased the GTF 8,400 heat rate by 6%; in fact, CVPS double-counted and applied that 6% increase twice.

Second, in its attempt to demonstrate reasonableness of the 8,900 BTU/kWh heat rate, DC&A testimony identified four non-utility combined-cycle projects that reported full-load heat rates greater than 8,400 BTU/kWh. Two of the four reported full-load heat rates of 8,500 BTU/kWh, which hardly support CVPS's 8,900 BTU/kWh value. More fundamentally, DC&A appear to be quoting the heat rates that the project developers selected to use in the pricing formulas for their projects, or values that were provided only for background information.[20] These were not necessarily the same as the heat rates expected by the developer. In addition, at least three of DC&A's sample of plants were to be cogenerators, which often report a heat rate of all fuel input divided by electric generation, even though some of the fuel is exported as heat. In sum, the numbers quoted by DC&A do not mean much and cannot support CVPS's unreasonably high combined-cycle heat rate.

2. Capital Costs

Q: What are DC&A's comments regarding combined-cycle capital costs?

A: In essence, DC&A speculate about factors that might have made reported costs of the Chesterfield 7 combined-cycle unit atypically low.

Q: What is the significance of DC&A's testimony on Chesterfield 7?

A: I do not understand their emphasis on Chesterfield 7. The only distinction of this unit was that it was actually in service in 1990, and its capital cost would have been readily available in 1991. If CVPS had thought this unit's costs

[20]The Altresco-Lynn contract with Boston Edison, for example, specifies fuel prices in cents per kWh for each year 1995–2014, without any reference to fuel cost or heat rate.

were atypically low, it could have sought out information on several combined-cycle units in development or under construction by 1991.

My direct testimony and Exhibit PLC-7 provided capital costs for six other units completed in the early 1990s. The capital cost I used in testing the comparability of utility-owned and NUGs was based on NYPA's R. M. Flynn plant (single unit on Long Island), at $723/kW, not Chesterfield 7 (part of a twin plant in Virginia) at $490/kW.

Q: Is the argument raised by DC&A regarding reported capital costs valid?

A: No. DC&A point (at 65) to the wide range of claimed projected costs for new non-utility combined-cycle plants in New England as somehow demonstrating that utilities' reported costs are subject to similar variations. This is an enormous leap, with no logical foundation.

3. Pipeline Charges

Q: What support do DC&A offer for a transportation cost of $1.33/MMBtu?

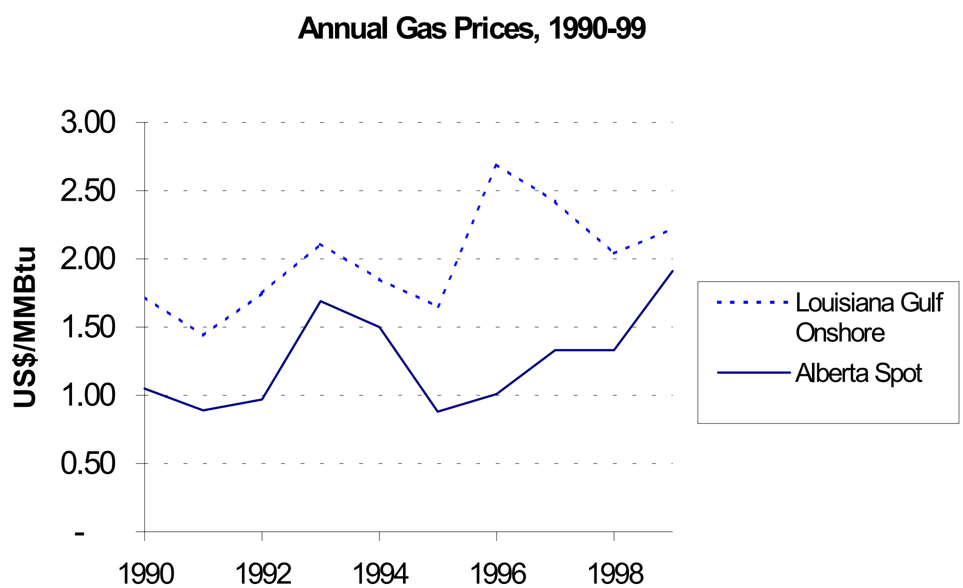
A: They claim (at 62–63) that this projection is consistent with the actual or projected costs at the time for firm deliveries from Canada to large non-utility generators in New England.

Q: Do the actual cost data cited by DC&A support CVPS's gas price assumptions?

A: No. DC&A are mixing apples and oranges. They use a projection of Gulf spot gas delivered to pipeline onshore as the basis for the gas commodity price, but uses Canadian gas-pipeline charges for the transportation-cost estimate. Since the commodity cost for Canadian gas is much less than that for Gulf gas, DC&A overstates the total cost of delivered gas.

Q: **Was the difference between the price of Canada gas and Gulf gas a well-known phenomenon?**

A: Yes. The following figure compares the actual prices of Alberta Spot and Louisiana Gulf Onshore prices delivered to pipeline, using data from *Natural Gas Week*.



Alberta Spot was consistently and significantly less expensive than Louisiana Onshore, one-third less on average.

Q: **Do DC&A attempt to adjust their forecast of the delivered-gas price for the cost differential between Canada and Gulf gas?**

A: No. DC&A have been unable to provide data on the difference between Alberta and US wellhead prices, as projected in the early 1990s (IR 5-24, 17-24).

Q: Were these differences between the cost of Canada and Gulf spot gas expected in the early 1990s?

A: Yes. WEFA (a major fuel-price forecaster, and GMP's source of forecasts in this period) forecasted roughly a $1/MMBtu cost differential for the years 1995–2015. I derived that differential from WEFA's May 1991 and 1993 forecasts, as explained in my surrebuttal testimony in Docket No. 6107 (Exhibit PLC-Sreb.-7 at 86–88).

C. Wheeling Charges for Purchases from Northeast Utility

Q: What is DC&A's position regarding wheeling charges for potential NU purchases?

A: They assert at 59 that my analysis "ignores the additional NEP wheeling that would have been required to transmit power to CVPS."

Q: What wheeling charges did you assume for the NU purchases?

A: I assumed the same wheeling charges that CVPS assumed for purchases from NU in its October 1991 analysis (Exhibit 3 to the 10/91 analysis, provided in Exhibit EMA R-1, Dockets No. 5701 & 5724).

Q: On discovery, were DC&A able to support their claim that additional wheeling charges were expected in the early 1990s, and should have been included in an analysis of the costs of alternatives to the HQ-VJO contract?

A: No. When asked to "provide all Company analyses and internal memoranda prepared in 1991 that demonstrated at the time that purchases of NU power would incur non-NU wheeling charges," DC&A were able only to provide "a document that demonstrates that as of 1987, purchases from NU would incur non-NU wheeling charges" (IR DPS 17-19). This document states that in

1987, CVPS expected to need wheeling through NEP or PSNH to deliver power from NU.

Of course, 1987 was not 1991, let alone early 1992, when CVPS might have been exploring alternatives to the HQ-VJO contract. In 1988, PSNH declared bankruptcy. By May 1991, the merger of PSNH into NU was sufficiently advanced that PSNH was able to emerge from bankruptcy. In April 1992, NU filed a unified system tariff, eliminating pancaking of rates for wheeling power across the combined system (IR DPS 5-37).

Contrary to DC&A's claim that the pancaking of NEP or PSNH rates with NU's rates "did not change until the NU-PSNH merger was completed in 1993–94 at which time the PSNH became part of NU" (IR DPS 17-19), the end of pancaking was foreseeable from the time that NU won the bidding war for PSNH in 1989 (or certainly by the time the New Hampshire Public Utilities Commission approved the merger in 1990), and was official by early 1992. Hence, it is not surprising that CVPS was unable to find any evidence from 1991 to support its claims.

VI. DC&A Modeling Errors

Q: What errors have you found in DC&A's modeling of the costs of alternatives to the HQ-VJO purchase?

A: I have had little time to review DC&A's many embedded assumptions, but I have found three groups of errors in the modeling, as follows:

- Failing to approximate economic dispatch.
- Adding excessive and uneconomic amounts of the 1998 Sheldon Springs clone, so called

- Using nominal, rather than real-levelized, costs for the 1998 Sheldon Springs clone.

Q: How did DC&A fail to approximate economic dispatch of their non-HQ portfolio?

A: In Exhibit DCA-9, DC&A adapted a spreadsheet model from GMP that takes as inputs the capacity and capacity factors for some resources and computes the required capacity and energy purchases from (or sales to) the market. The total portfolio thus calculated will provide the energy and capacity of CVPS's share of the HQ-VJO contract in each year. The spreadsheet then multiplies the capacity and energy of each resource by CVPS's projection of the price for that resource, to derive the portfolio cost for the year. This general approach, if implemented with reasonable inputs and structured with some care, can reasonably approximate the costs of a resource package that is a portion of the utility's total portfolio.

However, DC&A have structured this model in a way that does not realistically approximate the costs of the alternative portfolio, even given DC&A's arbitrary and unreasonable assumptions about the composition of the portfolio and the prices of the individual resources. DC&A have assumed that the non-HQ resources would operate in ways that are obviously uneconomic, given DC&A's assumptions about costs. In the short time available for review of this model, I have identified three problems in DC&A's treatment of the dispatch of resources.

First, DC&A assume that the NU Oil Block runs at very high capacity factors in some early years: 92% in 1996 and 52% in 1997. The two units included in this resource have relatively high heat rates and typically operated at capacity factors in the 20–25% range in the 1980s (with

Montville 6 occasionally up to 30%, in years when Middletown 4 ran at 15%). As DC&A reasonably assume, the average market price for power would be less than the costs of running the Oil Block, and the price outside the top 25% of hours would be even lower. Yet DC&A require the Oil Block to run, ignoring the option of lower-cost market purchases.[21]

Second, DC&A similarly require the generic combustion turbines that they add in 2006 to run at capacity factors of 17% to 27% in 2006 to 2012. The combustion turbines not only have high heat rates (DC&A assume 12,150 BTU/kWh, which they label as a "full load heat rate" but treat as an annual average heat rate) but burn expensive #2 distillate oil, rather than the #6 residual oil burned by oil steam plants (such as those in the Oil Block and Wyman #4). As a result, the energy costs of the turbines are much greater than the prices paid for market energy purchases. In the early 1990s, combustion turbines were not generally expected to run at capacity factors much above 5%. This modeling error added another few million to the cost of the non-HQ portfolio.

Third, for 2012–2015, DC&A reduce the output of the combined-cycle NUG (the 1998 Sheldon Springs clone), rather than selling its excess output into the market. DC&A assume that CVPS would continue to purchase the full capacity of the NUG in this period, but not use all its energy. Since their projection of the energy cost for the NUG is less than half their projection of

[21]In IR DPS 19-1(a), DC&A acknowledge at least part of this error: "The Exhibit has an error in 1996, whereby the capacity factor on the NU Oil Block reaches 93% in 1996. The spreadsheet should have been adjusted in that year so that there are Market energy purchases in 1996 and the NU Oil Block energy is reduced. This has a negligible impact on results." Reducing the Oil Block capacity factor to 30% in 1996 and 1997 reduces the present value cost of the portfolio by $2 million.

the market energy price, this is a highly inefficient decision. Again, this error added a few million to the cost of the non-HQ portfolio.

Q: Please explain why you say that DC&A added excessive and uneconomic amounts of the Sheldon Springs clone in 1998.

A: First, there would be no reason to purchase any power at the cost of new NUGs in 1998, since utilities in New England and New York expected to have excess capacity available for firm sales to 2000 or beyond.

Second, even if DC&A had some justification for assuming that CVPS could not have obtained a contract or an option for additional purchases in 1998, the resource choice DC&A makes for 1998 makes no sense. They add 60 MW of NUG combined-cycle capacity, which displaces most of the energy from the Oil Block.[22] Expensive as it is for a baseload purchase in the late 1990s, the energy from the Oil Block is still much less expensive than the cost of the NUG combined-cycle. For example, for 1998, DC&A project that the Oil Block energy charge would be $47/MWh (and market energy just $43/MWh), while the cost of the combined-cycle capacity (even netting out the cost of new combustion turbine capacity, which DC&A project to be more expensive than market combustion turbine purchases) is about $63/MWh. So the combined-cycle NUG capacity that DC&A arbitrarily added in 1998 is simply uneconomic.

Q: Do DC&A offer any justification for this choice?

A: After a fashion. In IR DPS 19-1(a), DC&A state that using the amounts of Sheldon Springs they assumed in 1994 and the amount of NU Oil Block

---

[22]As I explain above, that Oil Block energy should have largely been modeled as even-cheaper spot-market purchases, which would make the 1998 NUG even less economic.

capacity they assumed would be added in 1996 "to provide all of the HQ/VJO replacement energy…would result in an annual capacity factor of the NU Oil Block that was too high. Thus, a base load combined cycle resource was selected." In IR DPS 19-1(b) they state that "CVPS did not consider purchases of large blocks of power over long periods of time starting in 1998 from the short term market as viable options in supply planning." Of course, neither statement explains why the portfolio does not include more contract purchases, from the Oil Block or other sources.

In IR DPS 19-1(c), DC&A assert that "Iterative analysis showed that it was more economical to add more Bonneville clone capacity than that of the NU block." They do not provide any documentation of this analysis, so I do not know what iterations were actually performed. In any case, I suspect that DC&A grossly overstated the costs of adding more NU capacity in 1998, by compounding the error in its treatment of the replacement capacity for the Oil Block in 2006. DC&A assume that the Oil Block capacity will be replaced by combustion turbine capacity, which will also provide all the energy provided by the Oil Block.[23] Using DC&A's logic, substituting 60 MW of additional Oil Block for the 60 MW of the 1998 combined-cycle NUG would require the addition of an additional 60 MW of combustion turbine capacity in 2006-2015, operating at 80% capacity factor, bringing the average capacity factor for the entire group of combustion turbines in the portfolio to about 55%.

---

[23]Neither the Oil Block nor the combustion turbines are allowed to use any of the less-expensive market energy.

Q: What was DC&A's error in using nominal, rather than real-levelized, costs for the 1998 Sheldon Springs clone?

A: The problem with DC&A's treatment of the costs of the 1998 combined-cycle NUG is that they include only the sixteen early years of the plant's operation (1998–2015), and ignore the remaining nine years of the 25-year contract. Since the Sheldon Springs contract prices rose more slowly than inflation, the contract was front-loaded in real terms. In its last nine years, the contract would be less expensive than a new contract. DC&A simply ignore this "end-effects" value.[24]

The common solution to this problem is to levelize the cost of the resource in real terms (i.e., so that the cost rises with inflation), so that the costs allocated to the late years of an early project (e.g., 2017 for the 1998 unit) are the same as the costs of the early years of a late project (e.g., 2017 for a plant added in 2016). This is the approach that DC&A used for the costs of the combustion turbines that they add in 2006, and that CVPS has used for various avoided-cost and other planning analyses. For some reason, DC&A failed to make this correction for the 1998 combined-cycle NUG.[25]

DC&A's only excuse for failing to real-levelize the 1998 NUG costs was that "Pricing terms from NUG units were not real levelized" (IR DPS 19-1(f)). Of course, that is also true of utility combustion turbines (whose

---

[24]DC&A's modeling of Sheldon Springs with a 1994 in-service date, while unrealistic, has little of this end-effects problem, since DC&A include 23 years of operation for that plant, ignoring only two low-cost years.

[25]Actually, my direct testimony provided real-levelized costs for Sheldon Springs, so DC&A could have easily adopted my approach.

costs are even more heavily front-loaded), and all the other resources that CVPS has been able to real-levelize in the past.

VII. Conclusions

Q: Reviewing DC&A's criticisms of your analysis, have you changed any of your conclusions from your direct testimony?

A: No. The arguments that DC&A advance regarding externalities and risk are without merit.

With respect to the direct costs of the HQ-VJO contract and alternatives, from the perspective of the early 1990s, most of the arguments that DC&A advance are similarly erroneous. They did point out that I should have added some DSM to the non-HQ portfolio, and that I should have used a higher capacity factor for the combined-cycle plant, both of which would make the HQ-VJO contract less attractive. On the other hand, DC&A are correct that I should have included a New Unit Adjustment for the HQ-VJO contract (offset by similar adjustments for the NYSEG purchase and for new generation, such as the 2006 combined-cycle capacity), and recognized some value for the banking provisions of Sell-back 2 to the HQ-VJO contract.[26]

These offsetting corrections appear to be far too small to change my conclusions regarding the sort of portfolio CVPS would have selected if it had avoided the imprudent lock-in and then made prudent resource choices.

With regard to rate-year damages, DC&A's conclusions flow from their claims about externalities and risk, and the unfounded assertion that CVPS

[26] In October 1991, CVPS estimated that the banking was worth about $4.6 million.

would have revived the moribund Sheldon Springs NUG. None of these positions are valid. The minor adjustments they have correctly suggested for my early-1990s prospective analysis would not affect the rate year costs (the new combined-cycle would not yet be on line, NEPOOL NUA no longer exists, and the banking provisions of Sell-back 2 have ended), other than the addition of DSM to the least-cost portfolio, which would somewhat increase the damages in the rate years. Retrospectively estimating how the Company, the Department, and the Board would have adjusted CVPS's DSM programs in the absence of the HQ-VJO contract is inherently difficult, and I have not attempted it.

Hence, I have no change to the estimates I developed in my direct testimony of the rate-year damages due to CVPS's imprudent lock-in of the HQ-VJO contract.

Q: Does this conclude your surrebuttal testimony?

A: Yes.