Title
Evaluation Methods in Competitive Bidding for Electric Power. Volume 2: Technical Appendix

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Publication Date
1989-06-01

LBL-27450
UC-101

Lawrence Berkeley Laboratory

UNIVERSITY OF CALIFORNIA

APPLIED SCIENCE DIVISION

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Volume 2: Technical Appendix

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June 1989

APPLIED SCIENCE DIVISION

Prepared for the U.S. Department of Energy under Contract Number DE-AC03-76SF00098.

LBL-27450

EVALUATION METHODS IN COMPETITIVE BIDDING FOR ELECTRIC POWER

VOLUME 2: TECHNICAL APPENDIX

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† The work described in this study was funded by the Deputy Assistant Secretary for Coal Technology, the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

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TECHNICAL APPENDIX

PREFACE

This report is the technical appendix of an LBL study entitled "Evaluation Methods in Competitive Bidding for Electric Power," LBL-26924.

The technical appendices provide a detailed discussion of methods that can be used to measure and value various non-price factors in procuring electric power.

Appendix A

Evaluation of Front-Loaded Bids in Competitive Auctions

Private suppliers of electricity that participate in competitive auctions must specify a multi-year price trajectory. It may be desirable for some bidders to propose prices that exceed the buyer's estimate of value in the short run, but still offer substantial long run benefits. Prices of this kind are called "front loaded." From the buyer's perspective, bids which are front loaded are somewhat undesirable. They impose upon the buyer the risk that the long run benefits will not materialize if the supplier terminates delivery pre-maturely. Figure A-1 is a simple illustration of this situation. In this example, the bid price is fixed at a given level over the long term. The fixed price bid is less than the levelized avoided cost of the utility over the same period. In the short run, however, the utility over pays and incurs some financial exposure.

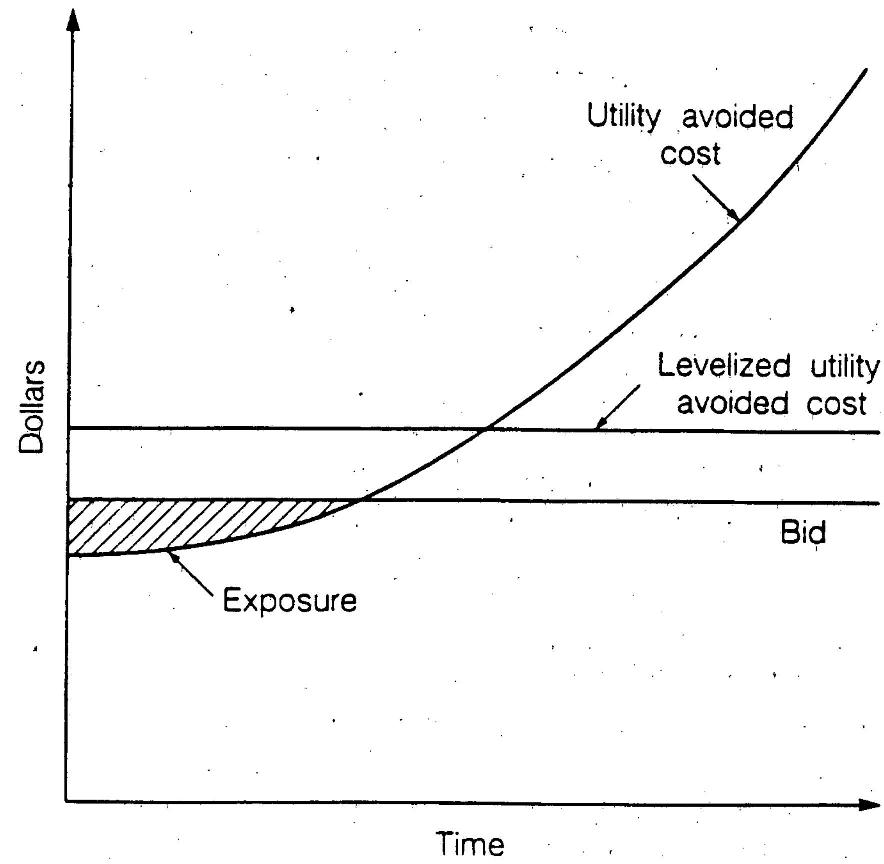
Private suppliers have entered into arrangements with utilities similar to Figure A-1 before the onset of competitive bidding. Usually the driving force behind front loading is the financing requirements associated with capital intensive technologies. These problems and some ad hoc methods of accounting for them have been described elsewhere (Kahn, 1988 ch. 6). With the advent of multi-attribute evaluation systems to select private suppliers through competitive bidding, rational methods for assessing bid features such as front loading are required. In this appendix, we develop a model to evaluate front-loaded bids, which we call the implicit loan (IL) method. In this model, we view front-loading to be a loan from buyer to seller. This notion, which has been suggested informally in the past, is formalized and made the basis for an explicit analytic evaluation method.

1. Front-Loading as a Loan

We begin qualitatively by considering two bids that have the same present value as the utility's avoided cost. The only difference between the bids is that one is front-loaded. The first bid, we call it the neutral one, is equal at every point to the utility's avoided cost stream. We believe that the other bid, which is front-loaded, is worse than the neutral bid. Let us separate the front-loaded bid into two parts. Part A is equal to the neutral bid at every point. Part B is just the difference between the neutral stream and the front-loaded bid. It is Part B which looks like a loan; negative cash flow in the early years followed by a positive cash flow.

In order for the front-loaded bid to be worse than the neutral bid, then Part B must have a negative value. How can this be? The arithmetic of present value only allows Part B to have negative value if we discount it at a rate greater than we are discounting the neutral bid. Does this make sense? Why should we introduce two discount rates into the analysis? The answer lies in the riskiness of the loan. Lenders are not certain that they will be repaid. That is why the interest rate that lenders charge borrowers is greater than what they pay to savers. The difference is a risk premium that accounts for the probability that some loans will default. The selection of a risk premium will be discussed in more detail in section 7. But for now we can say that

Figure A-1. A Front-Loaded Bid



this is not much different than selecting a risk premium for any other loan. Basically one should measure the exposure and duration of the loan, and compare its riskiness to that of other standard financial instruments. The result of this exercise might be a decision that the loan is equivalent to a 10 year, grade B bond. In this case the market return on such bonds can be used as the appropriate discount rate.

Conceptually, then we can describe the appropriate technique for evaluating front-loaded bids as a process of separation into a neutral and a loan component. The neutral part will be treated like any other bid (i.e., it will be evaluated at the utility's normal discount rate). The loan part will be discounted using a risk premium over and above the utility's normal discount rate. To formalize this concept, we must specify the meaning of neutrality, which will then allow us to define how to separate a bid into components.

Our approach, called the implicit loan (IL) method, rests on two assumptions. First, the utility's avoided cost stream defines neutrality. The neutral part of a bid should be proportional to the avoided cost. Second, the loan component is measured over the entire proposed contract length. It will be discounted at a risk-adjusted rate so that its present-value at that rate is precisely zero at the end of the power contract term. Algebraically, we can describe the IL method using Equations (1) and (2) based on the definitions given in Table A-1.

Table A-1. Definitions

C(t)	The bidder's cost stream, C(t) = P(t) + L(t)
P(t)	The neutral electricity payment component of C(t).
L(t)	The loan component of C(t).
A(t)	The avoided cost stream.
r	The utility's regular discount rate.
R	The loan interest rate (r + risk premium).
$PV_R[\,Y(t)\,]$	The present value† at rate R of stream Y.

$$C(t) = b \cdot A(t) + L(t) \tag{1}$$

$$PV_R[\,L(t)\,] = 0 \tag{2}$$

The first equation separates the bid stream into its neutral and loan components. The parameter "b," which we call the "price factor," is the proportionality constant defining the neutral component. It will be very useful as a means of incorporating the front loading risk directly into the price score, however that may be computed. The second equation defines the condition on repayment of the loan.

The IL method uses two parameters to characterize a front-loaded bid, b and R. These are mutually dependent. The loan interest rate, R, is higher when the loan is considered riskier. This means that the repayments (i.e., P-C), must be larger to offset the period when C-P is negative (which is the "implicit loan"). Therefore, a larger value of R means a larger value of b, which is the same as saying that the price score moves closer to avoided cost. Thus, the bid is less favorable to the utility. This inter-relation between b and R is the way in which the IL method rolls front loading risk into the price evaluation. We solve for b by re-arranging Equation (1) and then substituting for L(t) in Equation (2):

$$C(t) - b \cdot A(t) = L(t)$$

$$PV_R[\,C(t) - b \cdot A(t)\,] = PV_R[\,L(t)\,]$$

$$PV_R[\,C(t)\,] - b \cdot PV_R[\,A(t)\,] = 0$$

$$b = \frac{PV_R[\,C(t)\,]}{PV_R[\,A(t)\,]}. \tag{3}$$

† Present value is defined either as $\sum_0^{\infty} \frac{Y(t)}{(1+R)^t}$, if payments are made at the beginning of each year, or as $\int_0^{\infty} Y(t) \cdot e^{-Rt}\,dt$, if payments are made continuously.

Equation (3) gives us b, the "price factor" which is the ratio of the present values of the total bid stream and the avoided cost at rate R. Notice that the utility's normal discount rate does not even enter the calculation. If we know R, b is found easily. Conversely, if we know b, we can find R by iteration. The IL method can be applied to analytic problems starting at either point.

1.1 Describing the Loan

When evaluating the riskiness of a loan, an accurate description of it is essential. We are now able to compute the exact lending and repayment stream of the implicit loan, but while this is a complete description of the loan, it is not the most convenient. It will be found that the loan is made as well as repaid over an extended period of time. By using the concept of duration, we can assign a sensible number to the length of the loan, and by first computing its exposure as a function of time, we can find an equivalent starting date as well as the maximum exposure.

The duration of a loan is a measure of its effective length. Duration has the desirable property that a loan made at time t1 and repaid at time t2, with no intervening interest payments, has a duration of t2–t1. Duration is calculated as the time-weighted average of the present value of the payments, when the loan starts at time zero. We extend the concept slightly to encompass loans not made exclusively at time zero as follows.

$$\text{Duration} = \frac{PV_R[\, t \cdot L \,]}{PV_R[\, L^+ \,]} \tag{4}$$

L^+ indicates the positive part of L, i.e. the making of the loan (remember that L includes the repayments as negative values).

Exposure is the amount of the loan outstanding including unpaid interest. Denoting exposure as a function of time by X(T) we have:

$$X(T) = (1+R)^T \cdot PV_R^T[\, L \,]\,. \tag{5}$$

The superscript T on the PV denotes that the present value is only taken out to year T. The exposure stream can now be used to compute maximum exposure, which is important in assessing the riskiness of the loan. It can also be used to compute a midpoint for the loan. This is done as follows:

$$\text{Mid Point} = \frac{\sum_0^{\infty} t \cdot X(t)}{\sum_0^{\infty} X(t)}$$

2. A Concrete Example: R Known

The evaluation of front-loaded bids should have two goals: 1) to extract the normal rate of return on the loan, and 2) to insure the utility against the damages of a potential default. We will now look at an hypothetical example, and use it to evaluate the BECo/NMPC system in terms of the two goals just stated.

To demonstrate the above concepts in a realistic setting, we applied them to an example that uses an hypothetical bid contained in Western Massachusetts Electric Company's (WMECo) recent RFP. We analyze this data with the implicit-loan technique assuming that R, the risk-premium interest rate is known. In Section 3 we will evaluate this project using the bidding systems of Boston Edison (BECo) and Niagara Mohawk (NMPC) because WMECo's bidding system is non-linear and therefore more difficult to analyze. Our goal is to deduce the loan interest rate that would make the the implicit loan system equivalent to the BECo or NMPC point system. This will allow an economic interpretation of the point schemes. The data were picked simply for their availability, while the point systems were chosen for their clarity.

Table A-2 displays the implicit-loan (IL) analysis of the data. The first two columns show the payments to the bidder and the utility's avoided cost. These are both expressed in current dollars. The next column shows a present value multiplier for the loan discount rate, R in the above analysis. We use a value of R=15%, which is representative of the interest rate on high yield bonds with more default risk than conventional investment grade corporate bonds. For comparison, BECo's regular discount rate is 10.88%. From R=15% we calculate the stream of present values, taken at the loan rate, of both the payments and the avoided costs. These are summed to find the present values of the two streams, and these are presented above the relevant columns. Calculating b from equation (3) is now simply a matter of dividing the sum of the present value of payments by the total present value of avoided costs (see second line of table 2). Now that we have b, the implicit loan payments are computed from:

$$L(t) = C(t) - b \cdot A(t) .$$

These are displayed in the column labeled NOMINAL L(T). Although it is not displayed, the present value of the loan payments at the loan interest rate, R, has been computed and is zero as it should be. Finally equation (5) is used to compute the exposure as a function of time, and this is displayed in the column labeled X(L). Note that at its maximum in year 9, exposure is only a little less than the total nominal project revenue that year, C(T).

Table A-2. Implicit Loan Calculations at 15% Interest

R = 15%
b = 0.887 = SUM.PVC/SUM.PVA

	Nominal Payments C(T)	Nominal Avoided Cost A(T)	PV Multi-plier	SUM.PVC 159813 PV(C)	SUM.PVA 180097 PV(A)	LOAN NOMINAL L(T)	LOAN NOMINAL X(L)	LOAN REAL L(T)	LOAN REAL X(L)
						Assumed inflation = 5.0%			
0	16144	12510	1.000	16144	12510	5043	5043	5043	5043
1	16864	14244	0.861	14515	12260	4224	10083	4018	9592
2	17590	15111	0.741	13031	11195	4181	15896	3783	14383
3	19533	20240	0.638	12455	12906	1573	20041	1354	17250
4	19261	20325	0.549	10571	11155	1225	24510	1003	20067
5	21496	22841	0.472	10154	10789	1228	29704	956	23133
6	22744	23992	0.407	9247	9754	1454	35965	1077	26644
7	24345	27829	0.350	8519	9738	-350	41436	-246	29199
8	26154	31298	0.301	7877	9427	-1619	46522	-1085	31185
9	28361	37529	0.259	7352	9729	-4941	49110	-3151	31314
10	30759	42422	0.223	6863	9466	-6885	50173	-4176	30431
11	33405	46707	0.192	6415	8970	-8042	50251	-4640	28992
12	36260	50992	0.165	5994	8429	-8989	49394	-4933	27108
13	39270	55290	0.142	5587	7866	-9793	47595	-5112	24847
14	42058	59475	0.122	5150	7283	-10718	44579	-5323	22137
15	44867	63463	0.105	4729	6689	-11448	40345	-5408	19058
16	47767	67017	0.091	4333	6080	-11702	35173	-5258	15804
17	50883	73521	0.078	3973	5741	-14358	26507	-6137	11330
18	53830	80705	0.067	3618	5424	-17785	13012	-7231	5290
19	56791	81035	0.058	3285	4687	-15117	0	-5846	0

3. Application of Implicit Loan Method to BECo and NMPC Bidding Systems

To illustrate the perspective which the IL method provides, we examine the approach proposed by Boston Edison (BECo) and Niagara Mohawk (NMPC) to evaluate front-loaded bids. Note that the NMPC system is identical to BECO's in structure except that relative weights differ. We are concerned with the Price Factor and Economic Confidence Factor. Front loading is evaluated under the second heading. These systems evaluate front-loaded bids in terms of an implied loan maturity, in which a measure of the length of the loan period is computed and points are then assigned in inverse proportion to this length. Mitigation measures such as security deposits are also considered.

Table A-3 is a facsimile of BECo's Evaluation sheet 5 which we have filled in for the hypothetical bid included in the WMECo RFP. Columns [1] and [2] are the same as in Table A-2 and compare the annual over-payment of the developer's bid to the utility's avoided cost. The third column is a present value multiplier based on BECo's discount rate of 10.88%, rather than a loan interest rate as we used before. The present value of the bidder's payment stream and utility's avoided cost is calculated in columns [4] and [5]. Column [6] is nominal overpayment, which is simply column [1] - column [2]. Note that the nominal over-payment is negative when the developer's bid price is lower than the avoided cost. The annual over-payments are accumulated, with interest charged at the utility's normal discount rate in column [7]; each entry is the last entry times (100% + 10.88%) plus the current entry from column [6]. Note that the interest rate used is the utility's regular rate and is not adjusted for any riskiness in the loan. The accumulated balance is reduced and ultimately liquidated as avoided costs exceed the bid price in the later years of the project.

Table A-3. A Facsimile of BECo's Evaluation Sheet 5

Year	[1] Nominal Payments C(T)	[2] Nominal Avoided Cost A(T)	[3] PV factor at 10.88%	[4] PV of Payments	[5] PV of Avoided Cost	[6] Over Payment	[7] Cumulative Over Payment with Interest 10.88%	[8] Break Even Score
1990	16144	12510	1.000	16144	12510	3634	3634	0
1991	16864	14244	0.902	15209	12846	2620	6649	0
1992	17590	15111	0.813	14307	12291	2479	9852	0
1993	19533	20240	0.734	14329	14847	-707	10217	0
1994	19261	20325	0.662	12743	13447	-1064	10264	0
1995	21496	22841	0.597	12826	13629	-1345	10036	0
1996	22744	23992	0.538	12239	12911	-1248	9880	0
1997	24345	27829	0.485	11815	13506	-3484	7471	0
1998	26154	31298	0.438	11448	13699	-5144	3140	0
1999	28361	37529	0.395	11195	14815	-9168	-5687	1
2000	30759	42422	0.356	10951	15103	-11663	-17968	2
2001	33405	46707	0.321	10726	14997	-13302	-33225	3
2002	36260	50992	0.290	10500	14766	-14732	-51572	4
2003	39270	55290	0.261	10256	14440	-16020	-73203	5
2004	42058	59475	0.236	9906	14008	-17417	-98585	6
2005	44867	63463	0.212	9531	13481	-18596	-127907	7
2006	47767	67017	0.192	9151	12839	-19250	-161073	8
2007	50883	73521	0.173	8792	12703	-22638	-201236	9
2008	53830	80705	0.156	8388	12576	-26875	-250005	10
2009	56791	81035	0.141	7981	11388	-24244	-301450	11
			SUM	228437 SPVB	270801 SPVC			11 B.E.YRS

In BECo's system, the number of years until liquidation of the accumulated over-payment is called the break-even score (column 8). This is the key indicator of front-loading and is effectively a measure of the length of the front-loading loan. BECo gives a formula which typically (provided the overpayments never become positive a second time) counts the number of years with negative cumulative overpayment. This number is then divided by 20 and multiplied by 30 (equivalently, multiplied by 1.5) to give the "breakeven" score.

This project would receive 15.6 points on the price factor. The price factor is computed using the sum of the present value of payments (SPVB) and the sum of the present value of avoided costs (SPVC), which are shown at the bottom of columns 4 and 5. The specific formula for computing price factor points is:

$$Price\ Factor = \frac{(SPVC - SPVB)}{SPVC} \times 100 .$$

In essence, this formula gives 1 point for each percent by which payments are less than avoided costs. Finally, points are given for additional security provided by the seller to mitigate the affect of a front-loaded bid. Scores range between 0 and 20 points depending on the fraction of the overpayment that is secured. A bid that is not front-loaded, receives 20 points automatically.

3.1 Calculating the Implied Loan Interest Rate using BECo scoring weights

BECo's system produces a point score for each project, while the implicit loan (IL) method computes a price factor, b. These approaches are not directly comparable. However, we can compare them by creating a hypothetical project that receives the same overall score as our first project but which is not front-loaded. We then evaluate both bids using the IL method. If the IL method, at interest rate R, rates the front-loaded bid as better than the hypothetical project, then we can say that the BECo system is effectively charging some front-loading loans a higher interest rate than R. We solve for the implicit loan interest rate, R*, through iteration. This will allow us to say that, at least for the bid under consideration, BECo effectively charges interest rate R* for the front-loading loan.

We call our initial project, Project A and our comparable hypothetical project will be Project A*. Initially, we assume that Project A posts full security for its front-loaded bid, and receives 20 points in this category. The total score for Project A is then 52.1 points; recall that Project A received a breakeven score of 16.5 points and got 15.6 price factor points. To keep things simple, Project A* bids a payment stream that is proportional to the utility's avoided cost, and thus is not front-loaded. Thus, Project A* is awarded 30 points for the breakeven score and 20 points automatically for front-load security for a total of 50 points. Project A* must then receive only 2.1 price factor points in order to have an identical bid to Project A.

We use this information to compare the two bids using the implicit-loan method. A price score of 2.1 points means that Project A* has bid a payment stream that is 97.9% of the utility's avoided cost. Thus, b will simply be the ratio of those costs to avoided costs, which is 0.979. How does this compare with the evaluation of Project A's real bid shown in table 2? That evaluation gave $b = .887$, which is clearly much better. Thus, although the bids receive the same points under BECo's scoring system, the implicit-loan method does not judge the two bids as equivalent, but rather it judges the real bid as far superior. However, this conclusion is premature, because the value $b = .887$ was based on a loan interest rate of 15%, which is an ad hoc assumption (see Table A-2).

Table A-4. Implicit Loan Calculations at an Interest Rate (R*) that Generates b = .979

R = 25%
b = 0.979 = SUM.PVC/SUM.PVA

	Nominal Payments C(T)	Nominal Avoided Cost A(T)	PV Multi-plier	SUM.PVC 92309 PV(C)	SUM.PVA 94331 PV(A)	LOAN NOMINAL L(T)	LOAN NOMINAL X(L)	LOAN REAL L(T)	LOAN REAL X(L)
						Assumed inflation = 5.0%			
0	16144	12510	1.000	16144	12510	3902	3902	3902	3902
1	16864	14244	0.781	13167	11122	2925	7923	2783	7537
2	17590	15111	0.610	10724	9212	2803	12950	2536	11718
3	19533	20240	0.476	9298	9634	-273	16313	-235	14041
4	19261	20325	0.372	7159	7554	-628	20264	-514	16591
5	21496	22841	0.290	6238	6628	-855	25098	-666	19546
6	22744	23992	0.227	5153	5436	-734	31411	-544	23270
7	24345	27829	0.177	4307	4923	-2887	37341	-2035	26314
8	26154	31298	0.138	3613	4323	-4473	43352	-2998	29060
9	28361	37529	0.108	3059	4048	-8363	47159	-5333	30070
10	30759	42422	0.084	2590	3572	-10754	49645	-6522	30111
11	33405	46707	0.066	2196	3071	-12301	51282	-7097	29587
12	36260	50992	0.051	1862	2618	-13639	52040	-7485	28560
13	39270	55290	0.040	1574	2216	-14835	51815	-7744	27050
14	42058	59475	0.031	1316	1862	-16142	50220	-8016	24938
15	44867	63463	0.024	1096	1551	-17236	47083	-8141	22240
16	47767	67017	0.019	911	1279	-17813	42488	-8004	19091
17	50883	73521	0.015	758	1095	-21062	33354	-9002	14256
18	53830	80705	0.012	626	939	-25145	17573	-10223	7145
19	56791	81035	0.009	516	736	-22507	-0	-8704	-0

The obvious question is, what interest rate would make the bids equivalent under the implicit-loan method. We solved this problem through iteration and found that with b = .979, which is the same as for the BECo-equivalent contract, Project A*, the loan could be repaid using an interest rate of 24.7% (see Table A-4). Thus, if the appropriate loan interest rate is 24.7%, then BECo's scoring method is equivalent to the IL method, at least for this particular bid. Table A-5 shows the BECo scores and the IL price factor and equivalent interest rate.

Table A-5. BECo's Effective Interest Rate with Full Points for Front-Loading Security

Project A	Points
Price Factor =	15.6
Breakeven Score =	16.5
Front Load Security =	20.0
Sum =	52.1

Project A* (without front-loading)	Points
Eqivalent Price Factor =	2.1
Breakeven Score =	30.0
Front Load Security =	20.0
Sum =	52.1

SPVB/SPVC = b = 0.979
===> R = 24.7%

This result means that BECo's bid evaluation system effectively charges Project A an interest rate of 24.7% on the loan implicit in its front-loaded bid. The result is the same as if this interest charge were added to the bidder's true (absent the loan) payment series, and this augmented payment series were used to figure BECo's "price-factor" points. This economic interpretation allows us to cut through the confusion of the ad hoc point formula and find out, in a way that has meaning in the marketplace, how a front-loading loan is being treated. The answer is that the loan is being charged an interest rate that few would find acceptable. These results also are useful to the bidder. If the bidder can arrange a loan to cover their front loading, and if that loan charges less than 24.7%, they can accept the loan, pass all of the loan repayment through to BECo, and still do better on their BECo score.

What happens if Project A does not agree to post security for its front-loaded bid. In this case the project will receive 0 points for additional loan security and a total of only 32.1 points. We repeated the analysis for this situation. One would expect that with no loan security BECo should effectively charge a higher interest rate on the implicit loan. As table A-6 shows they do. They effectively charge 67.4% on this particular loan.

Note that Project A*, the non-front-loaded bid in table 6 receives *negative* price factor points and has a $b > 1$. This means that BECo is so leery of front loading that it treats the bid as harshly as it would treat a bid some 18% above avoided cost, if it decided to allow and evaluate such bids.

Table A-6, BECo's Effective Interest Rate
with No Points for Front-Loading Security

Project A		Points	Project A* (without front-loading)		Points
Price Factor points	=	15.6	Eqivalent Price Factor	=	-17.9
Breakeven Score	=	16.5	Breakeven Score	=	30.0
Front Load Security	=	0.0	Front Load Security	=	20.0
Sum	=	32.1	Sum	=	32.1
			SPVB/SPVC = b	=	1.179
			===> R	=	67.4%

3.2 Calculating the Implied Loan Interest Rate using NMPC scoring weights

Niagara Mohawk's proposed bid evaluation system is quite similar to the BECo point system with three simple but profound changes. The maximum number of points in NMPC's scoring system for price, breakeven score,, and additional front-load security are 850, 50, and 25 points respectively compared to BECO's system, which has maximums of of 100, 30, and 20 points for these factors. This drastically changes the relative importance of the breakeven score, and thus also the effective loan interest rate. Table A-7 shows how our project would fare under the NMPC scoring system, along with the implied loan interest rate. The effective interest rate being charged by NMPC on frontloading loans is much lower than BECO (13.2% and 16.3% respectively for loans with and without collateral).

Table A-7. NMPC's Effective Interest Rate with Full and with No Points for Front-Loading Security

Full Security

Project A	Points	Project A* (without front-loading)	Points
Price Factor =	133.0	Eqivalent Price Factor =	110.5
Breakeven Score =	27.5	Breakeven Score =	50.0
Front Load Security =	25.0	Front Load Security =	25.0
Sum =	185.5	Sum =	185.5
		SPVB/SPVC = b =	0.870
		===> R =	13.2%

No Security

Project A	Points	Project A* (without front-loading)	Points
Price Factor points =	133.0	Eqivalent Price Factor =	85.5
Breakeven Score =	27.5	Breakeven Score =	50.0
Front Load Security =	0.0	Front Load Security =	25.0
Sum =	160.5	Sum =	160.5
		SPVB/SPVC = b =	0.899
		===> R =	16.3%

4. Implications of the BECo/NMPC Point System

Because the BECo/NMPC system evaluates front-loaded bids relative to the avoided cost stream rather than the payment stream, the analysis of these systems must be conducted differently for payment streams that average near avoided cost than for payment streams with significantly lower payments.

4.1 Payment Streams Near the Avoided Cost Level

The most unusual property of the BECo/NMPC scoring method is its large discontinuity near the avoided cost payment level. For example, consider two contracts, one with a payments schedule that is two mills/kWh below the avoided cost schedule and the other contract with payments two mills/kWh above the utility's avoided cost. Despite the relatively small differences in bid price between these two projects, the first bid, which has no overpayments, gets a break-even score of thirty points, while the second project, which has an overpayment in every year, gets a break-even score of zero. To make matters worse, if the "high" bid does not put up collateral on its one-cent per year loan, it loses another twenty points. Fifty points in NMPC's system is equivalent to about a 4% decrease in payments (if taken from the price score), while in BECo's system it is comparable to a 50% decrease in payments.

The BECo/NMPC scoring systems also appear to be deficient in terms of differentiating risk based on the magnitude of a front-loaded bid. For example, let R be the interest rate and imagine a payment stream equal to avoided cost except at time 0 and time t. At time 0 the payment is high by \$L and at time t it is low by $\$L \times (1+R)^t$. Such a loan will not break even until year t and will therefore lose $t \times 1.5$ breakeven points. Thus the longer the period of the loan, the lower the BECo/NMPC score, which is reasonable. Next, we consider a loan of twice the size, \$2L, that is, of course, repaid in the amount $\$2L \times (1+R)^t$ at time t. Such a payment scheme will lose exactly the same number of breakeven points, in spite of the fact that it is clearly more heavily front-loaded. Notice also that the \$2L bid will garner the same number of points on the price factor. Thus, in this case, the BECo/NMPC system completely fails to account for the magnitude of front loading, probably the single most important determinant of risk.

4.2 Payment Streams Below the Avoided Cost Level

The scoring of front-loaded bids is less anomalous for cases in which contracts specify payment streams that significantly less than the utility's avoided cost stream, because the discontinuities in the point system are less of a factor. Nonetheless, the effects of discontinuities are still potentially a problem which could be exploited by clever bidders. To illustrate this problem, we compare three very simple hypothetical bids using Niagara Mohawk's initial scoring system (see Table A-8).[1]

The first project is designed to get 100 price-factor points, with payments that are 80% of avoided costs each year. Bid 2 has payments that are 112% for the first three years and 74% in the remaining years. The project receives 103.6 price-factor points, but loses 6 points for front loading. Thus, bid 2 loses to the first contract. The third bid has payments of 99% for the first 6 years and 72% in the remaining years. Bid 3 is awarded 100.3 price-factor points, loses no points for front-loading, and thus wins the auction.

We pose the question: should Bid 3 really be considered as totally lacking in frontloading? After all, the payment stream for this project is significantly higher during the initial years of operation compared to later years. One approach to this question is to compare contract 3 to contract 1, which is not front-loaded by any definition. Assume for a moment perfect competition, so that economic costs (including the cost of capital) equal revenues. Then it is quite likely that revenues for bid 3 will be well above long-run average costs for the first six years and below it thereafter. This means that the end of year six would be the most advantageous time for bidder 3 to default. If this happened how much would the utility stand to lose compared to a situation in which the utility selected bid 1? The utility will have paid the present value of 0.19 avoided cost units more than necessary for a period of six years. The total present value is about .894 avoided cost units using the utility's cost of capital as the discount rate (10.88%). We repeat the calculation for bid 2 and find that if this project had been selected and then defaulted at the end of the third year, the utility would have lost .868 avoided cost units. It seems that not

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[1] Niagara Mohawk Power Corporation, "Competitive Bidding Guidelines and Requests for Proposals," October 17, 1988. Note that NMPC submitted a revised integrated bidding system with a new point system on January 23, 1989.

Table A-8. Three Hypothetical Bids

	Percent of Avoided Cost		
	Bid 1	Bid 2	Bid 3
1st 3 years	80%	112%	99%
2nd 3 years	80%	74%	99%
Remaining years	80%	74%	72%
Price Factor Points	100	103.6	100.3
Breakeven Points	30	24	30
Security Points	20	20	20
Total Points	150	147.6	150.3

only does bid 3 include frontloading risk, but it is more risky than bid 2. Yet, bid 3 won the auction simply because it lost no points for front loading, while bid 2 lost the auction because of the 6 point penalty for its front-loaded bid.

5. A Discussion of Moral Hazard

One might think that the above examples are contrived, and thus not representative of a real-world bid. However, it must be remembered that bidders are in the business of contriving the most advantageous possible bid. This means that bidders are likely to take advantage of any system that has a loophole or can in any way be gamed. The only point system that is safe is one that reflects the true preferences of the utility with regard to all possible bids.

An example of gaming would be a bidder that engages in substantial frontloading, and combines this with unrealisticly low long-term prices, and who does this while avoiding any frontloading penalty. The BECo/NMPC system lends itself to this type of gaming if the utility's avoided costs are significantly above the eventual cost of viable accepted bids. The bidder must simply stay a shade below avoided cost but above long-term average cost for the first ten years. Then, the bidder offers very low costs for the remaining 10 years. The project can win on the basis of the low costs in later years, but the profit will be taken in the first 10 years after which the bidder will have less incentive to complete the contract.

A badly designed bid evaluation system can produce another undesirable result. It can induce suboptimal behavior by bidders even when they do not try to take advantage of a loophole. An example of this is a point system that effectively charges an interest rate much higher than the utility would actually require when making an explicit loan of the same riskiness.

Let us assume that the utility's treatment of front-loaded bids implies an implicit loan interest rate of 30%. However, the utility evaluates the riskiness of the project and believes that a loan with a 20% interest rate could be potentially profitable. The bidder, wanting to avoid the point penalty may find other long-term financing at 25%. The cost of this financing will of course have to be incorporated in the bid, but in spite of this the bid will have a better chance of success, and since the utility will end up paying for the loan the bidder has every reason to ated with these combinations. The procedure for designing this part of the bid evaluation system and scoring project bids would be:

1. Make a loan table giving interest rate for various exposure factors, and possibly durations.
2. Determine the avoided cost stream.
3. Pick a standard loan interest rate (R_o)
4. Compute b from equation 3.
5. Compute duration from equation 4.
6. Compute maximum exposure using equation 5.
7. Compute the PV of the payments stream until the date of maximum exposure, divide the maximum exposure by this to find an exposure factor.
8. Look up R in the loan table.
9. If $R \neq R_o$ then repeat from step 4.
10. If $R = R_o$ then use equation 6 to assign points, or equation 7 to assign dollars.

Finally, It is useful to draw some distinctions between this proposed evaluation system and our analysis of the BECo/NMPC scoring using the IL method (see sections 2 and 3). In our analysis, we did not need to know what interest rate to use with the IL method, instead we derived an interest rate that would make IL equivalent to BECo/NMPC. This allowed us to understand in economically meaningful terms how BECo/NMPC judged certain bids. However, we did not attempt to develop an independent IL score. To do this we have to choose the correct loan interest rate. That is why the proposed method that we have outlined in this section requires a loan table, while the previous analysis did not.

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Appendix B

Evaluating Fuel Diversity: Consumer Willingness to pay for Price Stability

Capital-intensive technologies are substitutes for oil and gas consumption. The value of this substitution depends upon the level of oil and gas prices, which are quite uncertain in the long run and unpredictable. One way to think about the value of fuel diversity is in terms of insurance. Over the long-term, electric bills are a gamble. They depend on uncertain future oil and gas prices to the degree that the utility depends on these fuels. Choosing solid fuel or renewable energy technologies will reduce the variability of future electricity revenue requirements. Our willingness to pay a premium for this reduction in variability reflects the insurance value of fuel diversity.

In this appendix, we describe our approach to estimating the benefits to ratepayers of fuel diversity. Our approach is based on conventional expected utility theory in which it is assumed that ratepayers preferences can be described by utility functions that have decreasing returns to income (see Chapter 4, Figure 4-3 and the discussion of risk-averse ratepayers for background). Thus, less additional utility is derived from an increase of $\$\Delta$ than is lost by a decrease of $\$\Delta$. This means that a typical ratepayer would be willing to pay somewhat more on their electricity bill if all uncertainty were removed compared to the expected situation in which bills could be lower but with some degree of uncertainty. The difference between the certain equivalent cost, which is higher, and the expected value is called the risk premium and reflects the relative risk-averseness of the ratepayer to the uncertainties in future fuel costs. The risk premium depends on the magnitude of the uncertainty and on the shape of the ratepayers utility function.

1. Theory

1.1. The Newberry-Stiglitz formulation

We want to estimate the benefits that are derived from removing the risk that fuel prices could be higher than expected. We use an approach developed by Newbery and Stiglitz in the context of commodity price stabilization. They derive an expression for the monetary benefit B of removing risk as a fraction of the consumer's expenditure on the source of risk X. In our case, X is ratepayers' expenditures on electricity, and B, the risk premium, is defined as follows:

$$U(Y_h+B, X) = U(Y_h, E(X)).$$

Here Y_h is the ratepayer's (household) income, a random variable. In order to make their approximation, Newberry and Stiglitz are forced to assume that

$$V(Y_h) \gg V(X),$$

where V() is the variance operator, and $\gg$ means "much greater than." Fortunately, in our case this is certainly true. A ratepayer is sure to be far more uncertain of his income twenty years in the future, than of his electric bill at that time. With this restriction in mind, the approximation for $\frac{B}{X}$ is:

$$\frac{B}{X} = -R \cdot CV(Y_h) \cdot CV(P) \cdot \rho(Y_h, P), \tag{1}$$

where R is the rate payer's relative risk aversion, CV() is the coefficient of variation, P is the price associated with X, and ρ is the correlation coefficient.

1.2. A Covariance Reformulation

Using the definitions of CV() and ρ, we can expand the above formula as follows,

$$\frac{B}{X} = -R \cdot \frac{SD(Y_h)}{E(Y_h)} \cdot \frac{SD(P)}{E(P)} \cdot \frac{COV(Yh,P)}{SD(P) \cdot SD(Y_h)}.$$

This equation can be reduced to:

$$\frac{B}{X} = -R \cdot \frac{COV(P^e, Y_h)}{E(P^e) \cdot E(Y_h)}. \tag{2}$$

We substituted, P^e for P, because the price of electricity to the ratepayer is the relevant price for our problem. This form will simplify our data requirements considerably.

In subsequent sections we discuss the correlations between GNP (Y) and various prices. Thus, it is convenient to have formula (2) expressed in terms of Y, instead of GNP/household (Y_h). We make that transformation now.

$$\frac{B}{X} = -R \cdot \frac{(1/h) \cdot COV(P^e, Y)}{E(P^e) \cdot (1/h) \cdot E(Y)} = -R \cdot \frac{COV(P^e, Y)}{E(P^e) \cdot E(Y)}. \tag{3}$$

Note that h is the number of households in the U.S., and that it conveniently cancels out.

1.3. A Model of the Interaction Between Y and P.

In order to apply the risk stabilization benefit formula, we must have a stochastic model of the future relationship between income (Y) and electricity prices (P). We first discuss a simplified model of the relationship between income and oil prices in order to take advantage of certain statistical identities which allows us to simplify the problem.

Consider the following model of the effect of oil prices on GNP.

$$Y = E(Y) + a \cdot (P^o - E(P^o)) + \varepsilon \tag{4}$$

In this model, Y and P^o represent the level of real GNP at time t, and the price of oil at time t. If the realized price of oil equals its expected price, then the second term is zero and the realized GNP will be its expected value plus some error (ε). We assume this error is uncorrelated with P^o. In reality the price of oil is not perfectly correlated with its effect on GNP, but assuming that it is, can only overstate the impact of oil price on risk.

This model allows us to simplify the estimate of the covariance between GNP and oil prices.

$$COV(P^o, Y) = COV(P^o E(Y)) + a \cdot COV(P^o, P^o)) - a \cdot COV(P^o, E(P^o)) + COV(P^o, \varepsilon)$$

$$COV(P^o, Y) = a \cdot V(P^o) \tag{5}$$

Note that E(Y) and E(P^o) are by definition the non-random parts of Y and P^o and therefore can have no covariance with any variable. The error term, ε, has no covariance with P^o for the same reason that the estimated error of a regression has no covariance with the independent variables: if ε were correlated with P^o another value of a could be found that predicts Y better. This is not quite the covariance we want, but that problem will be remedied once we establish the relationship between the price of electricity and the price of oil.

2. Data

We must select an appropriate value for the relative risk aversion parameter (R). We can think in terms of some average ratepayer whose risk preferences reflect the population at large. The key distinction is between the low-income consumer whose exposure to risk is large (R = 2) and the typical consumer (R = 1). We assume that 20% of the population falls into the low-income category and 80% falls into the second category, which implies a representative value of R = 1.2.

The expected value of oil prices over a twenty year horizon is a debatable quantity, and a question that must be decided by the ultimate user of this approach. However, some fairly standard and respected forecasts are available. We need an estimate of the "expected" or "most likely" prediction as well as estimates of the variance of this prediction. We used a DRI forecast that includes basecase, high, and low scenarios along with their probability weights, because variance estimates could be easily calculated.

We assumed that future GNP/capita, Y, grew at 1.5% per year, which is the average for the last 20 years. This estimate could probably be refined by more sophisticated forecasting techniques (e.g., include the expected change in household size).

Perhaps the most difficult parameter to estimate is a, the factor in Equation (4) that relates a change in the price of oil to a change in real purchasing power of the GNP. Huntington (1986) offers an excellent discussion of this issue. We will use his estimate of a $4 billion loss in real purchasing power for every $1 increase in the price of oil (i.e., $a = -4$).

2.1. An Illustrative Calculation

Our illustrative calculation uses gas prices rather than oil prices, because of the easy availability of the necessary forecasts. DRI has produced gas price forecasts with accompanying "high" and "low" price scenarios that are given explicit probability weightings. This allows a direct computation of DRI's estimate of $V(P^g)$, as well as $E(P^g)$. To obtain $V(P^o)$ and $E(P^e)$, relationships between oil and gas prices and between electric and oil prices will be needed. We assume the following two linear relationships as useful approximations. The parameter b is just the typical ratio of the price of gas to the price of oil, with oil measured in barrels, and gas in MBTU. The parameters c and d represent the fixed and variable costs in electricity generation.

$$P^o = b \cdot P^g$$
$$P^e = c + d \cdot P^g .$$

Taking the covariance of each with Y, we have:

$$COV(P^o, Y) = b \cdot COV(P^g, Y)$$
$$COV(P^e, Y) = d \cdot COV(P^g, Y)$$

We can now simplify the crucial covariance term. Start by eliminating $COV(P^g, Y)$ from the last two equations:

$$COV(P^e, Y) = \frac{d}{b} \cdot COV(P^o, Y)$$

Using (5):

$$COV(P^e, Y) = \frac{d}{b} \cdot a \cdot V(P^o).$$
$$= \frac{a \cdot d}{b} \cdot b^2 \cdot V(P^g)$$

And, finally:

$$COV(P^e, Y) = a \cdot d \cdot b \cdot V(P^g).$$

We can now re-write (3)

$$\frac{B}{X} = -R \cdot \frac{(a \cdot d \cdot b) \cdot V(P^g)}{E(P^e) \cdot E(Y)}. \qquad (6)$$

Now all that is needed is values for the parameters and the forecasts for P^g.

Two of the parameters, b and d, can be estimated from other sources. The third, c, can then be estimated from d and the prices of gas and electricity in 1988. The following table summarizes the value, economic units, and meaning of all of our parameters (table B-1). As a check on c we note that $\frac{c}{P^e_{88}} = .53$, which is near the current fraction of fixed costs in the price of electricity.

Table B-1. Parameters for Computing B/X

Parameter	Value	Units	Definition
a	-4	B (10^9)	Change in GNP / Change in P^o
b	15	1	Oil price / Gas Price
d	.011	1	MBTU's / kWH
P^e_{88}	.07	$1982	Price of electricity in 1988
P^g_{88}	3.0	$1982	Price of gas in 1988
c	.037	$1982	$P^e_{88} - d \cdot P^g_{88}$
Y_{88}	3788	$1982B	Real GNP in 1988

3. Estimates of the Benefits to Ratepayers of Stabilizing Electric Bills

Table B-2 shows our calculations of the benefits of stabilizing gas prices for ratepayers, B/X from (6), for each year of available data. We observe that B/X is always less than 1% in each year, ranging from about two-tenths to one-half of one percent over a 20-year period.

Table B-2. Estimates of Gas-Price Stabilization Benefit Ratio

1987 Data

Year	20% Low	60% Median	20% High	E(Pg)	V(Pg)	E(Pe)	E(Y)	B/X
	--Real	Price of	Gas--	= probability weight for scenario				
1987	0.926	2.125	3.438	2.148	0.631	0.061	3732	0.22%
1988	0.979	2.220	3.557	2.239	0.666	0.062	3788	0.23%
1989	1.118	2.309	3.734	2.356	0.688	0.063	3844	0.23%
1990	1.208	2.429	4.078	2.514	0.835	0.065	3902	0.26%
1991	1.259	2.524	4.533	2.673	1.105	0.066	3961	0.33%
1992	1.425	2.603	5.116	2.870	1.469	0.069	4020	0.42%
1993	1.460	2.755	5.496	3.045	1.755	0.070	4080	0.48%
1994	1.540	2.929	5.907	3.247	2.059	0.073	4142	0.54%
1995	1.677	3.116	6.168	3.439	2.173	0.075	4204	0.55%
1996	1.764	3.360	6.391	3.647	2.264	0.077	4267	0.55%
1997	1.798	3.642	6.603	3.865	2.384	0.080	4331	0.55%
1998	1.860	3.965	6.635	4.078	2.299	0.082	4396	0.51%
1999	2.010	4.311	6.757	4.340	2.254	0.085	4462	0.47%
2000	2.128	4.581	6.919	4.558	2.296	0.087	4529	0.46%
2001	2.324	4.874	7.025	4.794	2.220	0.090	4596	0.43%
2002	2.389	5.090	7.079	4.947	2.231	0.091	4665	0.41%
2003	2.588	5.361	7.051	5.144	2.063	0.094	4735	0.37%
2004	2.685	5.615	7.082	5.322	2.062	0.096	4806	0.36%
2005	2.845	5.807	7.077	5.469	1.962	0.097	4879	0.33%
2006	3.090	5.969	7.044	5.608	1.759	0.099	4952	0.29%
Grwth Rate	6.3%	5.4%	3.8%		MAXVAR 2.384		1.5%	

Notes: E(Pg) = Expected price of gas
V(Pg) = Variance in price of gas
E(Pe) = Expected price of electricity
E(Y) = Expected GNP

4. Alternative Variance Estimates

As explained above, DRI has provided high and low price forecasts, to which they have assigned a probability of 20% each. We calculated the variance of their estimated prediction error from these forecasts. One might expect that variance would increase monotonically over time, that it would be more difficult to predict the price in 2009 than in 1996. However, the variance of DRI's prediction error decreases over this time period to a little less then half of its 1996 value. Consequently, we are suspicious of their implicit variance estimates.

In order to assess the importance of a possible underestimation of uncertainty towards the end of the forecast period, we did a sensitivity analysis based on two alternative methods that "corrected" DRI's variance estimates. These will be referred to as the extrapolation method and the log-normal method. The extrapolation method begins by constructing a linear function that starts at zero in 1987 and increases fast enough to reach agreement with DRI's maximum variance value. This function continues to increase as the DRI variance estimate decreases. The extrapolation method takes as its variance in each year which ever is greater, the DRI variance or the linear function.

The log-normal method is based on the observation that most economic variables with non-negative probability distributions are observed to be skewed right (have a long right-hand tail). The log-normal distribution is one of the simpler distributions having this property. One property of such distributions is that their mean is greater than their median. We found that DRI's 1987 high forecast did not follow this pattern and so we derived a formula that replaced the high forecast with a high forecast that would be consistent with a log-normal distribution of future gas prices. Because the ln() of a log-normal variable is normally distributed we know:

$$\frac{\ln(P_{low}) + \ln(P_{high})}{2} = \ln(P_{median}).$$

Thus,

$$P_{high} = e^{2 \cdot \ln(P_{median}) - \ln(P_{low})}.$$

We then compared the benefits of stabilizing future fuel prices for electric ratepayers using the three methods to calculate the estimated variance in future fuel prices (see Tables B-3a and B-3b for results using the 1987 and 1988 DRI forecasts). We computed the present value of the term B/X for various discount rates (0% and 24%). We assumed that electricity sales increased by 2.4% per year over the forecast period, which was based on the basecase results from EIA's most recent long-term projections (EIA, 1989). The present value of the term B/X using the unmodified DRI forecast to estimate the variance is between 0.39% and 0.43% over this range of discount rates (see Tables B-3a and B-3b). The two alternate variance methods give higher estimates of the risk stabilization benefits (about 0.6 to 0.8) using the 1987 DRI forecast. This trend is less pronounced for the 1988 DRI forecast; only the extrapolated variance method has higher risk stabilization benefit than the uncorrected DRI forecast.

It is important to note that these estimates of the fuel price risk stabilization benefit must be modified to account for the difference between the retail price to the consumer and the wholesale price to the utility before they can be applied to the bid evaluation framework. For example, if a consumer had an annual electricity bill of $1000 (i.e., if X = 1000), then with B/X = 0.4%, the consumer would benefit by $4 from the switch from gas to coal. This $4 should be credited towards the bid of the coal-based bid. Since the ratio of wholesale to retail electric price (Ws/Rt) is typically between 1/2 and 2/3, the bidder should receive a credit of $4 on each $600 of electricity sold (assuming Ws/Rt = 0.6). This constitutes a credit of $4/$600 = 0.66% of wholesale price to the bidder. This procedure can be expressed algebraically as:

$$X = C \cdot \frac{Rt}{Ws}, \quad \textit{where } C = \textit{Wholesale cost.}$$

$$\frac{B}{C} = \frac{B/X}{Ws/Rt} = \frac{\$4/\$1000}{0.6} = 0.66\%$$

Table B-3a. Sensitivity analysis of fuel price risk premium using alternate variance methods (1987 DRI Forecast)

Real Discount Rate	---Fuel Price Risk Premium--- DRI Forecast	Log Normal	Extrapolated Variance	Mean-Median Discrepancy
0%	0.41%	0.98%	0.65%	10.7%
3%	0.41%	0.93%	0.63%	10.7%
6%	0.40%	0.87%	0.61%	10.7%
12%	0.39%	0.76%	0.56%	10.8%
24%	0.35%	0.60%	0.45%	11.2%

Assumed Growth rate of electricity = 2.4%

Table B-3b. Sensitivity analysis of fuel price risk premium using alternate variance methods (1988 DRI Forecast)

Real Discount Rate	---Fuel Price Risk Premium--- DRI Forecast	Log Normal	Extrapolated Variance	Mean-Median Discrepancy
0%	0.42%	0.39%	0.76%	5.6%
3%	0.43%	0.38%	0.73%	5.7%
6%	0.43%	0.38%	0.69%	5.8%
12%	0.43%	0.36%	0.62%	6.0%
24%	0.40%	0.32%	0.48%	6.1%

Assumed Growth rate of electricity = 2.4%

5. The Error of Using Median Value Forecasts

Underestimation of the high gas price forecast also leads to more serious errors in estimating the fuel price risk premium because future gas costs should be calculated as the expected present value (EPV) of the cost of gas. Unlike the median, the expected value depends on the high and low forecasts. Thus, an underestimated high gas price forecast leads directly to an underestimated EPV. Under the heading Mean-Median Discrepancy, Tables B-3a and B-3b show the extent of this bias for the two DRI data sets. The effect is about 11% for the 1987 forecasts and about 6% for the 1988 forecast.

A more elementary mistake can be made if a utility uses the median forecast in its computation of EPV, as if it were the mean forecast. Then, any time the future distribution of gas prices was skewed to the right, the expected present value would be underestimated. This mistake would lead to a downward bias in the estimate of EPV.

6. Incorporation of the Fuel Price Risk Premium into Bid Evaluation Systems

One way to incorporate the value of fuel diversity into a utility's bidding system is to adjust the bidder's energy price bid using the following formula:

$$\text{Adjusted Price} = (1 + \text{Risk Factor}) \times \text{Price}.$$

The adjusted price could be used in the point system exactly as price was used. Based on our analysis, the effect of this adjustment would be small, and would tend to favor projects that used non-oil and gas fuels.

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Appendix C

National Benefits of Reduced Oil/Gas Consumption

Because oil and gas are non-renewable resources, reducing the use of these fuels can have the benefit of reducing their long-run price. This benefit is external in the sense that it flows to all consumers, and not simply to those responsible for reduced oil and gas use. In this appendix, we provide some very rough estimates of the possible economic benefits of reduced oil consumption to the nation.

1: The Link Between Oil and Gas Merkets

We assume that a utility that purchases power from a producer that uses an alternative fuel (e.g., coal, hydro, biomass) effectively displaces some fraction of the potential oil and gas demand of the utility sector. Currently, oil- and gas-fired generating units are the marginal resources for most U.S. utilities. Gas is the dominant fuel, although much of the fossil-fueled U.S. generating capacity has the capacity to switch fuels.

In our analysis, we initially make the assumption that oil and gas are close substitutes over the longer term, which allows us to treat the complex links between world oil and gas markets in a quite simplified fashion. Over the long-term, we assume that using coal as an alternative fuel reduces the world demand for oil. This view is not realistic as these markets are functioning today. Currently, the linkage of oil and gas markets is weak because of substantial availability of gas supplies at low costs. Over the longer term, the ability of freed up gas to displace imported oil depends on one's view of the gas markets. If the weak linkage continues over the long run, this implies that the marginal cost of new gas supplies are not much higher than current embedded costs. The opposite view is that increased gas consumption will use up today's inexpensive supplies more rapidly. Moreover, the marginal cost of new gas supply is higher than current embedded costs and increasing. Under these conditions, the linkage of oil and gas markets is strong. Our analysis is based on the assumption of strong linkage. Therefore the estimates of the substitution benefits represent upper bounds. Should this view be incorrect, the benefits will be substantially lower.

We are particularly interested in the relationship between reduced world oil demand and the price of imported oil to the United States. Reduction in U.S. oil imports benefits the national economy by increasing domestic purchasing power and reducing the trade deficit. We assume that reductions in the price of domestic oil are in effect wealth transfers from U.S. producers to consumers, but have no significant net impact on the nation. The generation of electricity from non-oil/gas energy sources reduces the global demand for oil and thus its price. To the extent that the U.S. is a net importer of oil it will benefit from this price reduction. This appendix seeks to estimate the magnitude of this effect. We first explore the medium-run version of this effect, and then use the analytical framework developed in that section to explore long-run effects.

2. A Medium-Run Static Model

The response of oil price to a change in demand is far greater in the medium-run than in the long run. By medium-run we refer to the period of time during which the industry's capacity to produce is essentially fixed. Long-run refers to the period after capacity has been adjusted to the new level of demand. Unfortunately, the details of the medium-run price response depend on the internal dynamics of the OPEC cartel and are thus unpredictable in any level of detail. However, Hogan (1988) has demonstrated that OPEC pricing is sensitive to changes in capacity utilization and so *on average* a significant price response should be expected. In the long run world oil production capacity will adjust to the level of demand and the medium-run effect, which works through excess capacity will disappear. Thus the correct analysis of the effect of a demand reduction of one barrel/year is a large† price decrease that gradually dwindles. Estimating these dynamics would stretch already meager data well beyond the realm of credibility, so we will adopt a static approach.

Our analysis will consider only the effect of a change in oil price on the U.S. level of welfare, and not any possible impact of disruption due to sudden changes in the price of oil. For illustrative purposes, we begin with the medium-run analysis which looks at the change in price in the current year due to a change in demand that year. This effect will dwindle to zero as the capacity of suppliers adjusts to the changed level of demand. One would expect such an adjustment might be half complete in about six to eight years.

Formally, we want to estimate the part of the change in $P \cdot Q$ that is due to a change in P, where P is the price of oil and Q is the quantity imported by the U.S. We begin the problem by solving it for the world.

$$\frac{d}{dQ}(P \cdot Q) = \frac{dP}{dQ} \cdot Q + P$$

This can be made to appear more simple if we define a world "quantity" elasticity for oil supply as

$$\eta_s = \frac{dP}{dQ} \cdot \frac{Q}{P}$$

In this case the first equation simplifies to:

$$\frac{d}{dQ}(P \cdot Q) = \eta_s \cdot P + P$$

We are interested in the first term, which is the reduction in cost *due to the price* change if quantity demanded is reduced by one barrel. The second term is the reduction in cost due to not buying the barrel. This effect is obvious and is, of course, always taken into account by utilities

† "Large" must of course be interpreted relative to the size of the demand change. Since all the considered changes will actually be very small, the reader should bear in mind that a response of X must be interpreted as a response of expected value X. For small stimuli, this expected value is likely to be generated by a large probability of zero response and a small probability of a relatively large response. (Think of the impact of a single voter. Normally it has no impact, but very occasionally it swings the election.)

when they consider which fuel to use. However, the first term, $\eta_s \cdot P$, tells us how much the world will save if we refrain from the purchase of one barrel per year.

How much of the world savings accrues to the U.S.? We assume that the U.S. share of savings can be estimated by the share that U.S. imports represents of world oil production, which we call m. We can now write down the savings to the U.S. per barrel of oil not used. It is:

$$\text{Savings per barrel to U.S.} = m \cdot \eta_s \cdot P$$

We can take this one step further and evaluate the savings per kWh by using the number of kWhs typically generated by one barrel of oil, which we will call b:

$$\text{Savings per kWh} \equiv S = \frac{m \cdot \eta_s \cdot P}{b} \tag{1}$$

The most difficult task in estimating savings is choosing a value for the quantity elasticity η_s. For now, we arbitrarily guess that η_s has a value of 1, which represents a short run elasticity. In the medium run this elasticity will decrease, eventually to zero. The entire medium run effect is made up of successive years of this short-run effect as it dies out. Note that the reduction in oil demand must continue indefinitely, otherwise the increase in demand as demand returns to normal will produce a reverse medium run effect starting at the date at which demand reverts to normal. The future price of oil, P, is also difficult to estimate, but it is probably still known much more accurately than η_s. For this reason the standard error of S cannot be reduced much by improving the estimate of P. We will assume that oil prices are \$15/barrel (in real \$). Finally, we will use values for the conversion factor, b, of 580 kWh/barrel, based on an assumed heat rate of 10,000 Btu/kWh and the energy content of a barrel of oil (6×10^6Btu/bbl). We assume that m is 0.14, which is calculated by dividing a rough estimate of world oil production (50 million barrels/day) by U.S. imports (about 7 million barrels/day). Savings can now be estimated.

$$S = m \cdot \eta_s \cdot P \ / \ b$$

$$S = .14 \times 1 \times \$15/580 = \$.00357 = .36¢/kWh{=}36 mills/kWh \tag{2g}$$

3. A Long-Run Static Model

We now consider the impact of a one unit change in Q_o (where $Q_o = Q(0)$, and $P_o = P(0)$) on the future path of P. The next section will show that we can expect P to rise at the rate e^{rt}, and so any change in P_o will propagate to all later times. We now ask not for the change in $P \cdot Q$, by which we previously meant the change in $P_o \cdot Q_o$, but for the change in

$$\int_0^\infty P(t) \cdot Q(t) \cdot e^{-rt}\, dt$$

that is due to a change in price. This integral is, of course the present value of our stream of future oil imports. Now, employing the coming result on the growth of P(t) we have:

$$\begin{matrix}\text{present value of} \\ \text{all future oil imports}\end{matrix} = \int_0^\infty P_o \cdot e^{rt} \cdot Q(t) \cdot e^{-rt}\, dt$$

$$= P_o \int_0^{\infty} Q(t)\, dt$$

Or, for short:

$$PV = P_o \cdot Q^*$$

We define the long-run quantity elasticity as:

$$\eta = \frac{dP_o}{dQ_o} \cdot \frac{Q_o}{P_o}$$

We then follow the approach used in our short-run analysis and determine:

$$\frac{dPV}{dQ_o} - P = \frac{dP_o}{dQ_o} \cdot Q^*$$

$$\frac{dPV}{dQ_o} - P = \eta \cdot P_o \cdot \frac{Q^*}{Q_o}$$

This gives us the savings for the world, and once again we must convert to savings for the U.S. This requires multiplication by the ratio of q*, the total future imports of the U.S., to Q*, total world imports. This gives:

$$\text{Savings per purchased barrel to U.S.} = \eta \cdot P_o \frac{Q^*}{Q_o} \cdot \frac{q^*}{Q^*}$$

$$\text{Savings per purchased barrel to U.S.} = m^* \cdot \eta \cdot P_o, \qquad \text{where } m^* = \frac{q^*}{Q_o}$$

Note that m*, a measure of imports, is *much* larger than our previous measure of imports, m. M* measures the ratio of all future U.S imports to the current year's world production. We estimate it to be 16. This is equivalent to assuming that the U.S. imports an average of 10 million barrels/day for 80 years. The final conversion is to kWh and works the same as before.

$$\text{Savings per kWh} \equiv S = m^* \cdot \eta \cdot P_o / b \tag{3}$$

4. The Elasticity of Oil Price with Respect to Quantity

We must now evaluate η. This means answering the question: how much lower would the price of oil be if the U.S. used less oil? To estimate this elasticity we need a model of the oil market. Hogan (1988) has reviewed oil market models and finds a dichotomy between long-run optimizing models and *ad hoc* behavior models aimed at characterizing the dynamics of adjustment. We are interested in a long run model. Having no hope of predicting the dynamics of OPEC for the next 20 years, we will have to settle for trying to estimate the *expected* elasticity given our limited information. We will however adopt the DOE's Oil Modeling System as a characterization of the oil market. That is, we will take OPEC to be an effective cartel, and assume that other producers form the competitive fringe of the market. In other words, OPEC is the price leader and other producers are price followers. Although OPEC is clearly not an optimizing cartel, this approach will allow us to model that fact by simply reducing its size, thus giving it less power. Of course, there is no way to gauge OPEC's average effectiveness over the next 20 years with any degree of precision.

Because price followers base their production on price, but OPEC does not take price as given, it has an elastic demand function. We write it as follows, $Q(P)$, where P is world oil price as set by OPEC. Now OPEC's problem is to maximize profit as given by:

$$\Pi = P \cdot Q - C \cdot Q \approx P \cdot Q \tag{4}$$

To simplify our initial inquiry into this problem we are assuming that $C = 0$. This is not a bad assumption since lifting costs are only 1$ or 2$ per barrel. We define OPEC's elasticity of demand as:

$$\eta = \frac{dP}{dQ} \cdot \frac{Q}{P}. \tag{5}$$

We now consider OPEC's long-run view. It can choose either P or Q, but not both. For now we think of it as choosing Q(t) at each point in time from now until T, the exhaustion date of it's resources. In doing this, OPEC wants to maximize the present value of its profit stream, i.e.,

$$\text{maximize:} \qquad \Pi = \int_0^T P(t) \cdot Q(t) e^{-rt}\, dt.$$

This is a problem in the calculus of variations because OPEC is optimizing not over a variable but over the set of all functions Q(t). Fortunately, this is a solvable problem, at least in the case where the η is constant. We assume that η is constant. This isn't such a bad assumption since we (and more importantly OPEC) probably know nothing about how it will change.

To solve this problem we consider a small perturbation in Q at times t_1 and t_2. That is we consider (for OPEC) transferring some small amount of production, q, from time t_1 to time t_2. If profit is maximized with respect to this transfer for every possible time pair, then we have the optimal path for Q(t). We now differentiate profit with respect to this perturbation q.

$$\frac{d\Pi}{dq} = \left\{ \left.\frac{dP(t)}{dq}\right|_{t_1} \cdot Q(t_1) + P(t_1) \right\} \cdot e^{-rt_1} - \left\{ \left.\frac{dP(t)}{dq}\right|_{t_2} \cdot Q(t_2) + P(t_2) \right\} \cdot e^{-rt_2} \tag{6i}$$

This can be simplified by using the quantity elasticity:

$$\eta_{t_1} = \left.\frac{dP(t)}{dq}\right|_{t_1} \cdot \frac{Q(t_1)}{P(t_1)},$$

and the analagous definition of η_{t_2}. Substituting these into (6) gives:

$$[\eta_{t_1} \cdot P(t_1) + P(t_1)] \cdot e^{-rt_1} - [\eta_{t_2} \cdot P(t_2) + P(t_2)] \cdot e^{-rt_2} = 0$$

Now imposing our assumption that η is constant we have

$$P(t_1) = P(t_2) \cdot e^{-r(t_2 - t_1)} \tag{7}$$

This is an example of Hotelling's principle that price will increase at the discount rate (see Marshalla [1986] for an example of an optimization-based model based on this principle.

We now know the shape of the curve and only need a single point to fix it. Contrary to what might be expected, we choose the price at the exhaustion date, T, to fix the curve. At this date the price must equal that backstop price, which we assume follows an exponential decrease:

$$P_b(t) = P_b(0) \cdot e^{-at} \tag{8}$$

Thus at time T the backstop price is $P_b(0) \cdot e^{-aT}$. Using T as t_2 and the present as t_1 in equation (7) we have:

$$P_o = P_b(0) \cdot e^{-aT} \cdot e^{-rT}$$

Now we can see the effect we wish to estimate. If the U.S. substitutes coal for oil, this will delay the exhaustion date and thus both reduce the backstop price at the exhaustion date and increase the discount from then all the way to the present. These two effects show up in the two exponents of the above equation, both of which contain the exhaustion date T.

Now consider a change in the Q_o. It causes a change in price, which causes a change in the quantity sold at all subsequent dates. We let Qt be the average annual value of this quantity. So the exhaustion date T, should now be thought of as a function of both Q_o and Qt. To evaluate equation (3) we need the elasticity of P_o with respect to Q_o, which we can now evaluate as follows:

$$\frac{dP_o}{dQ_o} = \frac{dP_o}{dT} \cdot \frac{dT}{dQ_o}$$

$$\frac{dT}{dQ_o} = \frac{\partial T}{\partial Q_o} + \frac{\partial T}{\partial Qt} \cdot \frac{dQt}{dP_o} \cdot \frac{dP_o}{dQ_o}$$

$$\frac{dP_o}{dQ_o} \cdot \left\{1 - \frac{dP_o}{dT}\frac{\partial T}{\partial Qt}\frac{dQt}{dP_o}\right\} = \frac{dP_o}{dT}\frac{\partial T}{\partial Q_o}$$

$$\eta = \frac{dP_o}{dQ_o}\frac{Q_o}{P_o} = \frac{\dfrac{dP_o}{dT}\dfrac{\partial T}{\partial Q_o}\dfrac{Q_o}{P_o}}{1 - \dfrac{dP_o}{dT}\dfrac{\partial T}{\partial Qt}\dfrac{dQt}{dP_o}} \tag{9}$$

To evaluate this, we must evaluate three derivatives:

$$\frac{dP_o}{dT} = -P_o \cdot (a + r)$$

$$\frac{\partial T}{\partial Qt} = -\frac{T}{Qt}$$

$$\frac{\partial Qt}{\partial P_o}\frac{P_o}{Qt} = \eta^d = \rightarrow \frac{\partial Qt}{\partial P_o} = -\frac{Qt}{P_o}$$

Here η^d has been estimated to be -1. Equation 9 can now be evaluated as follows:

$$\eta = \frac{P_o \cdot (-a-r)\dfrac{1}{Qt}\dfrac{Q_o}{P_o}}{1 + P_o(a+r)\dfrac{T}{Qt}\dfrac{Qt}{P_o}}$$

Which simplifies to:

$$\eta = \frac{-c \cdot (a+r)}{1 + (a+r) \cdot T}, \quad \text{where } c = \frac{Q_o}{Qt}.$$

Assume that c = 1, a = .01 and, r = .025, T = 80. Then $\eta = .035$. We can now evaluate (3) as follows:

$$\text{Savings per kWh} \equiv S = m^* \cdot \eta \cdot P_o / b$$

$$S = 16 \times .0092 \times \$15 / 580 = \$0.0037/kWh = 3.7 mills/kWh$$

This value (3.7 mills/kWh) represents an average long-term value expressed in real dollars. At a minimum, we would expect that the long-term value would increase at the same rate as the increase in nominal oil prices; thus long-run effects of reduced oil demand if incorporated into bid evaluation systems, may also be large enough to affect the outcome of electric power auctions.

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Appendix D

Simulation of a Large-scale "Closed" Auction: Creating Representative Bids

We developed a method to simulate the bids submitted by potential suppliers in a utility's power auction, because, in almost all cases, the bids are not publicly available. In this appendix we discuss the key parameters that were used to describe bids, discuss prcoedures used to determine the mean value and range of each variable, and describe how input values were determined for each variable.

1. Deterministic or Random Simulation

In the broadest sense, bids can either be created through random or deterministic procedures, or a combination of both approaches. Bids can be generated from probability distributions that describe the variation in key parameters. The difference between the approaches lies in whether points from the distributions are chosen randomly or deterministically. To illustrate, let us assume that projects offered by bidders fall into one of three technology groups: coal, coal waste, and gas (referred to as technology types 1, 2, and 3.) We know that the probabilities of these bid types were 20%, 30% and 50% respectively in an actual auction. If we want a cluster of 10 bids, using the deterministic procedure would give us two bids of type 1, three of type 2, and five of type 3. With random simulation, each bid that is generated has the appropriate probability of being of type 1, 2 or 3. Thus, the random procedure will yield these same proportions on average, but is not guaranteed to produce these results in any individual case.

Deterministic simulation gives more realistic results where the procedure being evaluated does not depend crucially on coincidences which are forbidden under the deterministic procedure but allowed under the random procedure. We think this is unlikely to be the case in the present context. We used deterministic procedures for determining the set of values for each variable. Once these values were chosen they must still be combined to form bids. For example, if a bid can be described by two variables (e.g., X is project capacity, Y is bid payment) and we have chosen ten values for each, we must still decide how to pair those values. Pairing X1 with Y1 and X2 with Y2 will probably result in a high correlation between the two variables. In fact, in most cases, we would like to assure that the values are not correlated. This can be achieved either deterministically or randomly, but we chose to make the ordering random because a deterministic algorithm that works for any size bid cluster is much more difficult to implement.

2. The Bid Description

In our large-scale auction, supplier bids for each technology type were are described by four variables: generating capacity (C), fixed cost (F), variable cost (V), and fuel cost uncertainty (U). We picked sets of these four variables in creating our group of bids. The first three bid descriptors (C, F, and V) can in principle take any positive real value. Fuel cost uncertainty (U) is a qualitative dummy variables whose value was determined by fuel type (i.e., coal or gas). Thus, U contains part but not all of the information on technology choice.

3. Choosing Bid Technology (i) and Fuel Uncertainty (U)

The first step in simulating a bid is to choose the technology type (i). The cluster simulation method should be capable of producing bid clusters of any size, from single bids to a group of 50-100 bids. Therefore, we need a method of choosing a set of technology types that gives the best fit to our probability distribution on technology types for a specified number of bids.

Let P_i be the real-world fraction of bids that are based on technology type i. Assume that we have already selected the technology type for the first n bids (n may be zero). Let p_i be the fraction of the n bids that have already been selected that are based on technology type i. How do we select the technology type of the next bid? We adopt a rule that finds the type of technology that is most under-represented. In other words, select the value of i that maximizes $P_i - p_i$.

When selecting a total of N bids by the above method, all that needs to be kept track of is the total number of bids from each type of technology. These totals will be denoted by N_i.

Once the technology type of a bid has been specified, the value of U, the fuel type uncertainty variable was determined automatically. If $i = 1$ *or* 2 (coal or waste coal), then $U = 1$, while if $i = 3$ (gas), then $U = 2$.

4. Choosing Variable Cost (V)

We then made the simplifying assumption that variable costs were independent of both fixed costs and capacity; we also believe that this is a fairly reasonable approximation. The distribution of variable costs thus depends only on the bid's technology type.

The distribution of variable costs must allow only positive values. One of the most natural continuous distributions with this property is the log-normal distribution. Given our current lack of direct evidence on the subject, we assumed that variable costs have a log-normal distribution. We set the mean of that distribution (μ_i) based on the expected fuel costs for each technology type (coal, waste coal, and gas), as reflected in Virginia Power's assumptions. The variance of each distribution was more difficult to estimate. We estimated the coefficient of variation of variable costs for each technology based on expert judgment, which was then used to calculate the standard deviation of variable costs.

The next problem was to choose N_i points from the given log-normal distribution. These points should be at the centers of N_i consecutive equal area regions of the log-normal density function (see figure D-1). If F(V) gives the cumulative log-normal distribution function associated with V, then the appropriate values of V can be chosen as follows.

$$V_i = F^{-1}\left(\frac{i-.5}{N_i}\right) \tag{1}$$

We also want to make sure that variable costs (V) were uncorrelated with fixed costs (F) and capacity (c). If we applied a procedure like this to those variables, we would end up with perfect correlation. The most convenient way to avoid this problem was to randomize the order of the already selected V_i's.

In practice, we found that points in the extreme tails of the distribution created bids that were unrealistic. Hence, we truncated the lowest and highest 10% of the distributions, selecting values that represented only the middle 80% of the distribution.

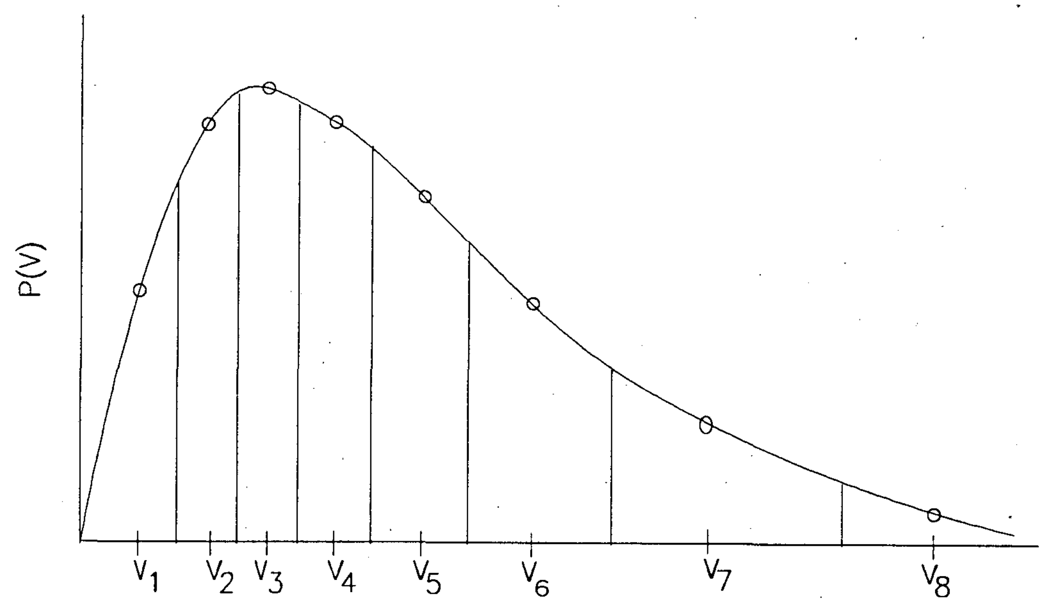

Figure D-1. 8 Values at the Centers of 8 Equal Area Regions of a Log-Normal Density

5. Choosing Capacity (C)

The procedure for choosing capacity (C) was similar to the procedure used in creating variable costs for each bid. We used a a log normal distribution and estimate its mean and variance from a sample mean and range. We then randomized a set of deterministically chosen values.

6. Choosing Fixed Costs (F)

Each technology type implies a relationship between capacity and expected fixed cost (e.g., economies of scale). For example, for coal, we assumed that the relationship has the form:

$$E(F) = \alpha \cdot C^{.8} \tag{2}$$

The first step in determining fixed costs was to compute $E(F_j)$ for the appropriate technology. The expected value of F_j serves as the mean of the log-normal distribution from which the actual F_i will be chosen.

Again, we used a set of evenly spaced log-normal values that have been randomized. We first, choose a coefficient of variation (CV) for the Fixed costs. Then, from a log-normal distribution with mean 1 and standard deviation CV, we selected N_i values that were spaced as in equation (1). We applied an order randomization technique as described above, and called the resulting values L_j. The N_i fixed cost for bids from technology i are now selected as follows:

$$F_j = L_j \times E(F \mid C_j) \tag{3}$$

7. Input Parameters

The following table shows the list of parameters needed for generating a cluster of bids. In this section, we discuss the value of each parameter, along with the method used to select that value.

i = (1,2,3) = (coal, coal waste, gas)	
P_i	The probability of each technology
$E(V_i)$, $SD(V_i)$	For Variable Cost
$E(C_i)$, $SD(C_i)$	For Capacity
α_i, β_i	As in E(F) = αC^{β}, where C = capacity
$CV(F_i)$	For Fixed Costs

The probabilities (P_i) of selecting each of the three technologies were derived from the "Virginia Power Bid Information Summary", hereafter referred to simply as VP (see Table 5-5). Virginia Power received 41 coal bids, 13 coal waste bids, and 24 oil-and-gas bids, along with several bids of miscellaneous type. We then calculated the probability of each technology type assuming that the number of bids represented the expected value (excluding the few miscellaneous type bids):

$$P_1 = 52.6\%$$
$$P_2 = 16.7\%$$
$$P_3 = 30.8\%$$

Mean values for the variable costs of the three technologies were based on proprietary data relating to bids submitted to VP.

$E(V_1)$ = 18.5 mills/kWh
$E(V_2)$ = 11.5 mills/kWh
$E(V_3)$ = 28.0 mills/kWh

The standard deviations were based on the above estimates of the mean and on expert judgement of the coefficient of variation of variable costs for each of the three fuel types. We estimated that the coefficients of variation were 0.1, 0.2 and 0.2 for coal, coal waste, and oil-and-gas, respectively. This produces the following estimates of the standard deviations.

$SD(V_1)$ = 1.85 mills/kWh
$SD(V_2)$ = 2.30 mills/kWh
$SD(V_3)$ = 5.60 mills/kWh

We computed the average capacity for each technology type based on public information on the number and total capacity of bids for each type that was released by Virginia Power from their RFP. We calculated the following mean values:

$E(C_1)$ = 200.3 MW
$E(C_2)$ = 82.2 MW
$E(C_3)$ = 201.8 MW

We then estimated the standard deviations of capacity from these expected values and coefficient of variation for each technology. The coefficient of variation was derived from the set of VP bids absent any bids that were clearly not from the technologies under consideration. The coefficient of variation of the capacity of the remaining bids was found to be 1.16. The implied standard deviations are:

$$SD(C_1) = 232.3 \text{ MW}$$
$$SD(C_2) = 95.4 \text{ MW}$$
$$SD(C_3) = 234.1 \text{ MW}$$

Note that there is no problem with the standard deviation being greater than the expected value. This is possible with a log normal distribution, and no negative capacities will be simulated.

The next two sets of parameters are associated with the equation that links the expected value of fixed costs with capacity. Once again, that equation is:

$$E(FixedCost) = \alpha \cdot Capacity^{\beta} \tag{4}$$

Fixed cost in the above equation refers to the total fixed cost of a project, which is not the same as the variable, F, the fixed cost per kWh of capacity, used in our bid simulation. We can rewrite the above equation in terms of the bid simulation variables:

$$E(F \cdot C \cdot 1000) = \alpha \cdot C^{\beta} \tag{5}$$

The "fixed cost" in now in dollars, and the capacity in megawatts. For the first two technologies, coal and coal waste, the value of β was estimated to be 0.8, based on expert judgement. We then solved for α as follows:

$$\alpha = \frac{F \cdot C^{(1-\beta)}}{1000} \tag{6}$$

We were able to obtain two data points for each technology from proprietary sources involved in the VP bid that were used to fit this equation. For coal, the first data point is (F=330, C=300) and yields an estimate of $\alpha = 1.033$. The second is (F=225, C=75) and yields $\alpha = .534$. We used the average of these two values of α.

For coal waste, the first data point is (F=390, C=80), which yields $\alpha = .937$, and the second point is (F=440, C=50) which yields $\alpha = .962$. Again, we used the average.

For oil and gas technology we have no expert estimate of the economies of scale, β, but we do have two data points from actual bidders. Consequently, we were forced to estimated both α and β from these two points. The formula for β is the following:

$$\beta = 1 + \frac{ln(F_2) - ln(F_1)}{ln(C_2) - ln(C_1)} \tag{7}$$

The two data points are (F_1=130, C_1=220) and (F_2=200, C_2=45). These yield estimates for α and β, which are shown in the following table along with those for coal and waste coal.

Coal	$\alpha_1 = .78$	$\beta_1 = .8$
Waste Coal	$\alpha_2 = .95$	$\beta_2 = .8$
Gas	$\alpha_3 = .56$	$\beta_3 = .73$

The last parameters needed for bid-cluster simulation, are the coefficients of variations of fixed costs (F_i) given α, β, and C_i. (These could equally well be viewed as coefficients of variation for the three $\alpha's$.) As an admittedly rough estimate of these parameters, we used the coefficient of variation of the two estimates of α_1 of the two coal data points (1.003 and .534). For lack of data we were obliged to use this same estimate for all three technologies.

$$CV(F_1) = .32$$
$$CV(F_2) = .32$$
$$CV(F_3) = .32$$

We then created a cluster of 90 bids in our simulation of a large-scale dispatchable auction using the methods described in this appendix; values for simulated bids are summarized in Table D-1.

Table D-1. Bids used in simulation of large-scale "closed" auction.

Technology Type	Plant No.	Fuel Type	Capacity (MW)	Variable Cost ($/MWh)	Fixed Cost ($/kW)
COAL	1	COAL	408.	19.42	227.07
COAL	2	COAL	377.	17.70	240.19
COAL	3	COAL	350.	20.82	322.58
COAL	4	COAL	328.	20.07	224.97
COAL	5	COAL	308.	18.73	187.82
COAL	6	COAL	290.	18.33	288.13
COAL	7	COAL	274.	20.19	263.01
COAL	8	COAL	260.	16.27	281.34
COAL	9	COAL	247.	19.52	288.48
COAL	10	COAL	235.	20.64	201.62
COAL	11	COAL	224.	17.86	330.85
COAL	12	COAL	214.	18.25	190.76
COAL	13	COAL	205.	18.89	319.17
COAL	14	COAL	196.	18.10	354.17
COAL	15	COAL	188.	18.57	279.87
COAL	16	COAL	180.	19.72	260.45
COAL	17	COAL	173.	16.89	391.34
COAL	18	COAL	166.	18.49	240.72
COAL	19	COAL	159.	17.94	249.54
COAL	20	COAL	153.	20.33	190.55
COAL	21	COAL	147.	17.18	310.82
COAL	22	COAL	141.	18.81	288.37
COAL	23	COAL	136.	16.99	279.26
COAL	24	COAL	131.	16.55	289.05
COAL	25	COAL	126.	19.62	216.56
COAL	26	COAL	121.	19.23	194.45
COAL	27	COAL	116.	18.97	351.71
COAL	28	COAL	111.	17.53	271.67
COAL	29	COAL	107.	17.27	239.95
COAL	30	COAL	103.	17.09	329.09
COAL	31	COAL	99.	19.06	270.79
COAL	32	COAL	95.	16.78	329.90
COAL	33	COAL	91.	17.45	259.92
COAL	34	COAL	87.	18.41	266.09
COAL	35	COAL	83.	19.33	272.37
COAL	36	COAL	80.	16.67	399.46
COAL	37	COAL	76.	18.64	448.86
COAL	38	COAL	72.	18.02	374.37
COAL	39	COAL	69.	19.95	311.37
COAL	40	COAL	66.	16.42	251.32
COAL	41	COAL	62.	19.83	276.16
COAL	42	COAL	59.	17.62	441.22
COAL	43	COAL	55.	19.15	244.78
COAL	44	COAL	52.	18.17	320.70
COAL	45	COAL	49.	17.36	432.88
COAL	46	COAL	45.	20.48	289.71
COAL	47	COAL	42.	17.78	253.21
AVERAGE FOR TECHNOLOGY			157.	18.45	288.23
ST. DEV. FOR TECHNOLOGY			94.	1.22	64.15

Table D-1 (continued) Bids used in Simulation of Virginia Power Auction

Technology Type	Plant No.	Fuel Type	Capacity (MW)	Variable Cost ($/MWh)	Fixed Cost ($/kW)
WASTE COAL	1	MSCL	154.	11.76	344.63
WASTE COAL	2	MSCL	125.	12.10	330.56
WASTE COAL	3	MSCL	105.	11.60	447.84
WASTE COAL	4	MSCL	90.	10.44	276.39
WASTE COAL	5	MSCL	78.	11.29	317.25
WASTE COAL	6	MSCL	69.	10.21	554.65
WASTE COAL	7	MSCL	61.	12.82	278.68
WASTE COAL	8	MSCL	54.	11.14	375.06
WASTE COAL	9	MSCL	47.	10.98	367.79
WASTE COAL	10	MSCL	42.	12.54	511.37
WASTE COAL	11	MSCL	37.	10.64	500.79
WASTE COAL	12	MSCL	32.	10.82	602.54
WASTE COAL	13	MSCL	27.	12.30	371.86
WASTE COAL	14	MSCL	23.	11.92	525.72
WASTE COAL	15	MSCL	19.	11.44	503.86
AVERAGE FOR TECHNOLOGY			64.	11.47	420.60
ST. DEV. FOR TECHNOLOGY			38.	0.75	102.37

Technology Type	Plant No.	Fuel Type	Capacity (MW)	Variable Cost ($/MWh)	Fixed Cost ($/kW)
GAS	1	NG	401.	26.33	120.38
GAS	2	NG	353.	30.01	113.52
GAS	3	NG	317.	30.30	138.62
GAS	4	NG	287.	25.87	97.34
GAS	5	NG	262.	29.73	138.40
GAS	6	NG	241.	30.99	96.53
GAS	7	NG	222.	27.17	109.65
GAS	8	NG	206.	28.79	165.14
GAS	9	NG	192.	30.63	88.91
GAS	10	NG	179.	27.37	139.62
GAS	11	NG	167.	27.96	124.26
GAS	12	NG	156.	28.37	163.41
GAS	13	NG	146.	25.05	154.46
GAS	14	NG	136.	27.56	105.56
GAS	15	NG	128.	28.16	136.62
GAS	16	NG	120.	26.11	142.25
GAS	17	NG	112.	31.42	218.15
GAS	18	NG	105.	26.55	192.39
GAS	19	NG	98.	29.48	153.68
GAS	20	NG	91.	29.24	121.80
GAS	21	NG	85.	28.57	217.24
GAS	22	NG	78.	26.76	230.14
GAS	23	NG	72.	24.71	182.32
GAS	24	NG	66.	25.35	174.29
GAS	25	NG	61.	25.62	159.44
GAS	26	NG	55.	26.96	155.98
GAS	27	NG	49.	29.01	133.88
GAS	28	NG	43.	27.76	157.72
AVERAGE FOR TECHNOLOGY			158.	27.92	147.56
ST. DEV. FOR TECHNOLOGY			95.	1.84	36.34

Appendix E

Simulation of a large-scale "closed" auction: Optimization results

This appendix describes our approach and results in using EGEAS's Benders decomposition option to select a set of planning alternatives from a distribution of simulated bids. We offer the initial caveat that our EGEAS simulation was limited by some of the peculiarities and constraints of the EGEAS model as applied to our application. These include: a limit on the number of projects that can be examined concurrently, difficulty in getting the Benders decomposition algorithm to converge consistently, and the generally difficult and unfriendly EGEAS user interface.

We began by generating a distribution of 90 bids using the process described in Appendix D. We were forced to evaluate bids in an elimination style tournament because EGEAS has a limitation of 30 planning alternatives. The 90 bids were divided into three heats of 30 bids each. To assure uniformity of the heats, the planning alternatives were sorted by technology and capacity and then evenly distributed. Specifically, for each technology the largest, fourth largest and seventh largest projects were grouped together as were the second largest, fifth largest, and eighth largest projects, etc.

The optimization was conducted over a ten-year planning period (1988-1998) and new plants were selected based on their relative life-cycle costs over a 30-year forecast period. Thus, the financial implication of the construction of each plant was evaluated over a long-term time horizon.

In some cases it was not possible to get the Bender's algorithm to converge (run to completion) throughout the entire ten-year planning period. This occurred when the problem is improperly constrained or there was insufficient capacity in the planning alternatives to meet system demand and reliability constraints. In some cases the optimization period was shortened to accommodate these constraints and the tournament was held on a shorter planning horizon. In the worst case the optimization period was truncated in 1995. We recognize that this may affect our choice and relative timing of bid acceptance, but believe the ultimate effect to be small, particularly since we always optimize over the period in which Virginia Power planned to accept bids (1990-94).

Plants that were accepted by the optimization algorithm between 1990-1994, the planning period specified by the Request for Proposal (RFP) (Virginia Power 1988a), advanced to further rounds of competition. Although running this sort of multi-round elimination tournament is not as desirable as running a single-round tournament, we suspect that its effect on the final outcome of the auction is minimal.

Benders decomposition does not require plants to be of integer size. In some cases the final solution can ask for some fractional capacity of a bid. Because we constrained each bid to being accepted only once we found that in nearly every case EGEAS elected to build the entire plant that was built. Sometimes, it took more than a single year to accept all of a plant. We interpreted this to be a case where a plant may come on line in the middle of the year rather than at the beginning. In this case we accepted a bid if all of the plant's capacity were needed by the end of the period specified in the RFP.

Each initial run of 30 bids accepted 13-18 bids. Typically, a second round would consist of two runs each with 23-27 bids. Plants were sorted by type and size and then divided into two uniform groups by capacity. The winners from the second round advanced to a final round. Final round winners were considered to be bids that were selected.

Three different simulations were performed using the 90 bid set. A base case, which used the Virginia Power system as described in the RFP and avoided cost filing, and two sensitivity cases, one case with higher gas and distillate prices (see Table E-1) and a second case in which the fixed cost of each coal and waste coal project was reduced by $40.00/kw-yr. The results of the sensitivity analysis are summarized in Tables E-2 and E-3.

Performing the optimization and creating proper EGEAS input is a time consuming process. EGEAS has an archaic and frustrating user interface, while the Benders decomposition option had difficulty finding solutions and frequently required a lot of effort to be made to run. It was often necessary to alter reliability constraints in order to get Benders to proceed beyond the first few iterations. EGEAS provides very little guidance as to the cause of the problem. We found that this occurred most often when the early iterations of Benders violated constraints on unserved energy. We were able to get past these early rounds by raising the allowable unmet energy to be fairly high (over 10% in some cases). In the final plans generated the unserved energy levels fell to reasonable levels (i.e. 100 GWh/year maximum) that could be met with emergency power.

EGEAS was designed to solve the capacity expansion problem, which is typically a larger and combinatorially more complex problem than the 0-1 bid-takers problem. For this reason EGEAS was able to solve the largest of our auction problem quickly and easily once convergence problems were eliminated. The constraints on the number of planning alternatives (30 for linear programming and Benders decomposition and 10 for dynamic programming) seems artificial and too low for bid evaluation. Virginia Power received nearly 90 bids in their auction. EGEAS would be a much better tool if these constraints were relaxed. It is also possible that another optimization algorithm, which is designed to take advantage of the 0-1 constraint, may be more efficient and easier to use than Benders Decomposition.

Our use of tunnel constraints to assure that no more than one of each bid can be accepted provides us with additional information about each auction because the dual multipliers on the tunnel constraint for each plant gives the marginal value of the plant to the utility in that auction. The dual prices of each plant accepted by the optimization are listed in Table E-4. The model calculates one dual price per bid. We have divided these by plant capacity to express them in a somewhat normalized fashion. The normalized dual prices show relative value within a scenario. Caution should be used when comparing dual prices between scenarios; because each run was conducted with slightly different time and reliability constraints (due to difficulties using Bender's decomposition). Thus, dual prices between scenarios reflect costs under different time horizons and are not comparable.

Table E-1. Virginia Power and DRI High Gas Price Forecasts
(in $/MMBTU)

Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
VP Forecast *	2.74	2.84	2.45	2.62	2.87	3.15	3.22	3.57	3.98	4.50	5.10
DRI High Gas Forecast	N.A.	N.A.	5.14	5.74	6.62	7.70	8.79	10.16	11.56	12.96	14.37

* Source: Virginia Power Request for Proposal 1988 Bid Solicitation.
Assumes heat rate of 10,000 MBTU/kWh

Table E-2. Bids Accepted by EGEAS in Each Tournament

Base Case

Type	Plant #	Capacity MW	Fixed $/MW	Variable $/MWH
Coal				
	5	308	187.82	18.73
	12	214	190.76	18.25
	total	522		
	average	261.00	189.29	18.49
Waste Coal				
	5	78	317.25	11.29
	7	61	278.68	12.85
	total	139		
	average	69.50	297.97	12.07
Gas	1	401	120.38	26.33
	4	287	97.34	25.87
	6	241	96.53	30.99
	7	222	109.65	27.17
	9	192	88.19	30.63
	11	167	124.26	27.96
	14	136	105.56	27.56
	20	91	122.8	29.24
	total	1737		
	average	217.13	108.09	28.22

DRI High Gas Forecast

Type	Plant #	Capacity MW	Fixed $/MW	Variable $/MWH
Coal				
	5	308	187.82	18.73
	12	214	190.76	18.25
	20	153	190.55	20.33
	25	126	216.56	19.62
	26	121	194.23	19.23
	29	107	239.95	17.27
	40	66	251.32	16.42
	total	1095		
	average	156.43	210.17	18.55
Waste Coal	2	125	330.56	12.1
	5	78	317.25	11.29
	total	203		
	average	101.50	323.91	11.70
Gas				
	4	287	97.34	25.87
	6	241	96.53	30.99
	7	222	109.65	27.17
	9	192	88.19	30.63
	14	136	105.56	27.56
	total	1078		
	average	215.60	99.45	28.44

Coal fixed Price Reduced $40.00

Type	Plant #	Capacity MW	Fixed* $/MW	Variable $/MWH
Coal				
	5	308	187.82	18.73
	12	214	190.76	18.25
	20	153	190.55	20.33
	26	121	194.23	19.23
	40	66	251.32	16.42
	total	862		
	average	172.40	202.94	18.59
Waste Coal	2	125	330.56	12.1
	5	78	317.25	11.29
	7	61	278.68	12.85
	total	264		
	average	88.00	308.83	12.08
Gas	2	176	113.52	30.01 **
	4	287	97.34	25.87
	6	241	96.53	30.99
	7	222	109.65	27.17
	9	192	88.19	30.63
	14	136	105.56	27.56
	total	1254		
	average	209.00	101.80	28.71

* Price Before Reduction
** 1/2 Capacity used by 1994

Table E-3. Summary of Tournament Results

Base Case

# of Plants	Total Average MW	Average Capacity MW	Average $/kW	Average $/MWh	Percent of Capacity
2	522	261	189.29	18.49	21.8%
2	139	70	297.97	12.07	5.8%
8	1737	217	108.09	28.22	72.4%
12	2398	200	153.27	23.91	

DRI High Gas Forecast

# of Plants	Total Average MW	Average Capacity MW	Average $/kW	Average $/MWh	Percent of Capacity
7	1095	156	210.17	18.55	46.1%
2	203	102	323.91	11.70	8.5%
5	1078	216	99.45	28.44	45.4%
14	2376	170	186.88	21.10	

Coal Fixed Price Reduced $40.00/kW-yr

# of Plants	Total Capacity MW	Average Capacity MW	Average $/kW	Average $/MWh	Percent of Capacity
5	862	172	202.94	18.59	36.2%
3	264	88	308.83	12.08	11.1%
6	1254	209	101.80	28.71	52.7%
14	2380	170	182.28	21.53	

Table E-4. Dual Prices ($/kW)

	Bid #	Capacity MW	Base Case	DRI High Gas	$40 Coal Credit
Coal	5	308	213	344	356
	12	214	227	357	364
	20	153	103	247	244
	25	126	134	45	
	26	121		256	271
	29	107		23	
	40	66		4	17
Waste Coal	2	125		179	12
	5	78	45		187
	7	61	267		410
Gas	1	401	92		
	2	354			
	4	287	308	937	167
	6	241	273	944	155
	7	222	177	827	40
	9	192	341	1021	229
	11	167	49		
	14	136	211	861	74
	20	91	64		

Appendix F

Methods used to score eight generic bids in three utility evaluation systems

In this appendix, we describe how we used the eight project bids that were prepared by teams of participants at a workshop sponsored by the California utilities in February 1989. The purpose of the workshop was to acquaint the community of regulators and private suppliers with the multi-attribute bid evaluation system being proposed by the utilities (see Section 6.1 for a more detailed summary of the organization of the workshop and our adaptation of the bidding data to our purposes). We illustrate the differences among the bid evaluation systems of three utilities by scoring the same set of eight bids in hypothetical auctions.

Tables F-1(a,b,c) show a detailed listing of the points awarded for each factor by the three utilities: Orange & Rockland Utilities, Boston Edison, and Niagara Mohawk. These tables come from the RFP's issued by the utilities and provide a sense of the overall weighting factors that will be used to score projects. In addition, the utilities have developed a point system for each particular attribute; points are awarded to projects based on their relative benefits to the utility. We used these more detailed scoring forms to score our eight generic bids.

Tables F-2, F-3, and F-4 give the project bid scores for the eight bids in our hypothetical auctions conducted by ORU, NMPC, and BECo, respectively. We also provide a detailed description of the assumptions that were used to score each factor that was included in the bid evaluation system of each utility (see notes that accompany each table). In many cases, it was easy to make a direct comparison and translation of the factors that were included in the California game to the other three scoring systems. However, in a fair number of cases, we had to make subjective judgments about the attributes of each project in order to score it in one of the three utility bidding systems. Our assumptions are detailed in the notes that accompany each table. In general, where information on an attribute was not available based on the data from the California workshop, we tended not to differentiate among the eight bids, so as not to unduly influence the relative ranking of the projects.

Table F-1(a). Orange & Rockland Utilities.

7.4 PROJECT SCORE SUMMARY TABLE: MAXIMUM AND ESTIMATED

	Maximum Possible Project Score	Estimated Proposed Project Score
I. Economic Factors		
A. Price	50.0	____
B. Dispatchability	4.0	____
C. Security Provision	0.5	____
D. Price risk	0.5	____
	----	-----
Subtotal	55.0	____
II. Project Status and Viability Factors		
A. FERC Certification as QF	1.0	____
B. Project schedule and milestones	2.0	____
C. Project permitting plan and schedule	2.0	____
D. Project financing plan and schedule	2.0	____
E. Project development team & experience	2.0	____
F. Project technology	2.0	____
G. Thermal output user	2.0	____
H. Engineering design	3.0	____
I. Wheeling/Interconnection Considerations	2.0	____
J. Stability/security of fuel supply	2.0	____
K. Site control	3.0	____
L. Form of liquidated damage fund	2.0	____
	----	-----
Subtotal	25.0	____
III. Non-Economic Factors		
A. Fuel type	4.0	____
B. Location	1.0	____
C. Environmental benefits	7.0	____
D. Fuel (thermal) efficiency	3.0	____
E. Length of contract	5.0	____
	----	-----
Subtotal	20.0	____
TOTAL	100.0	____

Table F-1(b). Boston Edison Company.

RFP #2
SCORING SYSTEM

NOTE: This schematic shows the point range for each component of the scoring system.

Ratepayer Avoided Costs	0 to 100	PRICE FACTOR	0 to 100
Payments To Q.F.	SEE ABOVE		
Breakeven Period	0 to 30	ECONOMIC CONFIDENCE FACTOR	0 to 50
Front Load Security	0 to 20		
Tech./Environ. Feasibility	0 to 10	PROJECT DEVELOPMENT CONFIDENCE FACTOR	0 to 50
Q.F./Project Team Experience	0 to 6		
Level of Development	0 to 30		
Additional Contract Deposit	0 to 4		
Debt & Operating Coverages	0 to 6	OPERATIONAL LONGEVITY CONFIDENCE FACTOR	0 to 20
Fuel Supply	0 to 6		
Maint: O&M Contract or Escrow	0 to 2		
Optional Operating Security	0 to 6		
Dispatchability/Interrupt.	0 to 10	SYSTEM OPTIMIZATION FACTOR	0 to 30
Fuel Type	0 to 10		
Size	0 to 2		
Location	0 to 4		
Maintenance Schedule By BECo	0 to 4		

Level of Development components:

Siting	0 to 10
Design & Engin.	0 to 4
Permit. & licen.	0 to 6
Financing	0 to 6
Thermal Energy	0 to 2
Construct./Oper.	0 to 2

TOTAL PROJECT SCORE	0 to 250

NIAGARA MOHAWK POWER CORPORATION
SCORING SYSTEM

SUPPLY SIDE

(Maximum Scores Indicated)

Avoided Costs/Payment	~~500~~ 850

PRICE FACTOR	~~500~~ 850

Breakeven Score	~~30~~ 50
Front Load Security	~~20~~ 25

ECONOMIC Risk Factor	~~50~~ 75

Site Acquisition	10
Design & Engineering	10
Permit & Licensing	10 ~~7~~
~~Environmental Benefit~~	~~3~~
Facility Availability	10

Construction/Operation	2
Thermal Energy	2
Financing	6

Tech./Environ. Feasibility	40
Level of Development	10
Project Team Experience	6
Addit'l Contract Deposit	4
Economic Development	4

Success Factor	64

TOTAL PROJECT SCORE	~~600~~ 1200

Fuel Supply	7
Debt Coverage	6
Operation & Maintenance	2
Optional Operating Security	6

Longevity Factor	21

Unit Commitment	14 ~~7~~
Economic Dispatch	20 ~~10~~
Automatic Generation Control	10 ~~8~~
Black Start	6 ~~2~~

Operations Optimization	~~28~~ 50

Location	4
Unit Size	3
Fuel Diversity	10
Fuel Flexibility	8
Quick Start Ability	5

Planning Optimization	30

Operational Factor	~~58~~ 80

Environmental Rating	100
Environmental Benefit	10

Environmental Factor	110

Table F-1(c). Niagara Mohawk Power Company.

Table F-2. Project bid scores in Orange and Rockland Utilities bid evaluation system.

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas-fired Cogen #1	Gas-fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Economic Factors									
Price	50	11	10	0	4	9	10	22	20
Dispatchability	4	4	4	0	0	0	0	4	4
Security Provision	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Price Risk	0.5	0	0	0	0	0	0	0	0
Project Status & Viability Factors									
FERC Certification as QF	1	1	1	1	1	1	1	1	1
Schedule/Milestones	2	2	2	2	2	2	2	2	2
Permitting plan & schedule	2	2	2	2	2	2	2	2	2
Financing plan & schedule	2	0	0	2	2	0	0	2	2
Development team & experience	2	2	2	2	2	2	2	0	0
Project technology	2	2	2	2	2	2	2	2	2
Thermal Output user	2	0	0	0	0	2	2	2	2
Engineering Design	3	3	3	3	3	3	3	3	3
Wheeling/Interconnection	2	2	2	2	2	2	2	2	2
Security of fuel supply	2	0	0	0	0	0	0	0	0
Site control	3	3	3	3	3	0	0	0	3
Form of liquidated damages	2	0	0	2	0	0	0	0	2
Non-Economic Factors									
Fuel type	4	2	2	2	2	4	4	4	4
Location	1	1	1	1	1	0	0	1	1
Environmental Benefits	7	2	2	2	2	4	4	4	4
Fuel (thermal) efficiency	3	3	3	3	3	3	3	3	3
Length of Contract	5	5	5	5	5	5	5	5	5
PRICE FACTORS	50	11	10	0	4	9	10	22	20
NON-PRICE FACTORS	50	34.5	34.5	34.5	32.5	32.5	32.5	37.5	42.5
TOTAL	100	45.5	44.5	34.5	36.5	41.5	42.5	59.5	62.5

	Mean	Std Dev.
PRICE FACTORS	10.75	6.87
NON-PRICE FACTORS	35.13	3.20

Notes on Table F-2: Scoring Bids in ORU's bid evaluation system.

Economic Factors

1) Price Factor: Points awarded based on % of avoided cost from Table P9 (p. 47).

2) Dispatchability: Projects with manual dispatch get 4 pts; curtailable up to 1500 hrs get 0.

3) Security provision: No front-loading, then no security req'd (0.5 pts); Four projects are front-loaded, but bid price does not exceed ceiling price by more than 20% for gas or 35% for geothermal/biomass, so these projects also get 0.5 points.

4) Price risk: All projects either escalate at GNP or gas prices; so get 0 points.

Project Status and Viability Factors

5) FERC Certification as QF: Assume yes for all projects (1 pt.).

6) Schedule/milestones: Lead time for biomass and geothermal are 2 yrs; CC and cogen is 3 yrs; thus maximum points for all projects.

7) Financing plan: Gave points for four projects (biomass and cogen) with average debt coverage ratios greater than 1.5.

8) Development team experience: Biomass less experienced than rest of projects (0 pts); Other projects (2 pts).

9) Project technology: All projects have mature technology; so get 2 points.

10) Thermal output user: CC and Cogen do not have firm thermal host agreement; only letter of intent, so 0 points.

11) Engineering Design: Assume all projects get maximium pts.

12) Wheeling/Interconnection: Assume wheeling not required for any project (within utility service territory); so get 2 points.

13) Security of fuel supply: All projects have only identified a specific transport and fuel plan (0 pts).

14) Site control: CC and Cogen, and Bio#2 projects purchased firm site control (1% of capital cost), they get 3 pts; Other projects get 0 pts.

15) Form of liquidates damages: Two projects purchased project failure security in form of cash (2 pts); Others get 0 pts.

Non-economic factors

16) Fuel Type: Solid waste and renewable get 4 pts; Gas gets 2 pts.

17) Location: Assume Geothermal project is not near load center (i.e., environmental constraints), so gets 0 points.

18) Environmental benefits: Waste,hydro other renewables get 4 pts; Fossil fuel get 2 pts.

19) Fuel (thermal) efficiency: Assume all projects get 3 points.

20) Length of contract: All projects get max. points (5).

Table F-3. Project bid scores in Niagara Mohawk's bid evaluation system.

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas-fired Cogen #1	Gas-fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
Economic Risk Factor									
Breakeven Period	50	30	50	0	20	23.3	50	50	46.7
Front Load Security	25	0	25	0	0	0	25	25	25
Success Factor									
Tech./Environ. Feasibility									
Site Acquisition	10	10	10	10	10	0	0	0	10
Design & Engineering	10	6	6	6	6	6	6	6	6
Permit & Licensing	10	5	5	5	5	5	5	5	5
Facility Availability	10	10	10	10	10	10	10	9	9
Level of Development									
Construct./Oper.	2	0	0	0	0	0	0	0	0
Thermal Energy	2	0	0	0	0	2	2	2	2
Financing	6	4	4	4	4	4	4	4	4
Project team experience	6	6	6	6	6	6	6	2	2
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Economic Development	4	1	1	3	3	3	3	1	1
Longevity Factor									
Fuel Supply	7	7	7	7	7	7	7	3	3
Debt & Operating Coverages	6	0	1	4	4	0	0	1	1
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
Operational Factor									
Operations Optimization									
Unit Commitment	14	14	14	6	6	6	6	14	14
Economic Dispatch	20	20	20	8	8	8	8	20	20
Automatic Generation Control	10	0	0	0	0	0	0	0	0
Black Start	6	0	0	0	0	0	0	0	0
Planning Optimization									
Location	4	4	4	4	4	1	1	4	4
Unit Size	3	0	0	0	0	0	0	3	3
Fuel diversity	10	4	4	4	4	6	6	8	8
Fuel Flexibility	8	6	6	6	6	0	0	6	6
Quick Start Ability	5	5	5	0	0	0	0	0	0
Environmental Factor									
Environmental Rating	100	77	77	80	80	51	51	80	80
Environmental Benefit	10	0	0	0	0	0	0	0	0
PRICE FACTORS	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
NON-PRICE FACTORS	350	209	255	167	183	138.3	190	243	253.7
TOTAL	1200	353.5	382.5	167	242.5	257.3	317.5	523.5	517.2

	Mean	Std. Dev
PRICE FACTORS	140.25	87.92
NON-PRICE FACTORS	204.88	40.21

Notes on Table F-3: Scoring Bids in NMPC's bid evaluation system.

Price

1) Price Factor: % of Avoided Cost; 0 avoided cost gets 850 points

Economic Confidence Factors

2) Breakeven Period: Five projects have some front-loading. For these projects, we calculated break-even periods by adding yearly PV of benefits for all three scenarios until year in which it became positive. We then used NMPC formula to determine points.

3) Frontload security: Projects that were not front-loaded (CC#2, Geo#2, and Bio#1) get maximum points (25 points). Two projects posted failure security as cash equivalent (Cogen #1 and Bio #2). We calculated % that security represented of cumulative overpayment and awarded full points for Bio#2 and 0 points to Cogen#1 on this basis.

Success Factor

4) Site acquisition: CC, Cogen, and Bio #2 purchased firm site control (10 pts); Other projects have no firm site control (0 pts).

5) Design & Engineering: Assume all projects have detailed design & engr. plans (6 points).

6) Permit and Licensing: All projects have identified required specific permits. In addition, points are given to various projects because not all permits are required for each technology (not applicable gets maximum points for a particular permit. Worked with QF consultant to determine applicable permits for each of four technologies. Ultimately, all projects ended up receiving 5 points.

7) Facility Availability: Biomass has 80% availability; so gets 9 points. Other projects are more mature (10 pts).

8) Construction/Operation: All projects not under construction (0 pts).

9) Thermal Energy: Geo and Biomass are renewable (2 pts); CC and Cogen do not have firm thermal host agreement; so get 0 points.

10) Financing: Assume all projects have 50% financing (4 points).

11) Project team experience: Biomass has developed QFs (similar scale but different technology); so get 2 pts; Other projects have developed similar facilities (6 pts).

12) Additional Contract Deposit: Bio#2 and Cogen#1 offered project failure security in cash, so we assume they receive maximum points (4 pts); Other projects get 0 pts.

13) Economic development: We used first-year O&M costs as proxy for number of jobs that would be created. O&M costs are $3.2M for CC, $3.8M for Cogen, $1.8M for Geo, $1.1M for Biomass. We then assumed that salary was $40,000 per job and divided O&M costs by that amount to estimate the number of jobs created. CC and Cogen received 3 points on this basis; Geo and Biomass received 1 point.

Longevity Factor

14) Fuel Supply: Biomass has less development experience (QF facility but different technology), so we assume that they have no experience in managing fuel procurement/transport). On this basis, biomass gets 3 points. Other projects receive maximum points (7).

15) Debt & Operating Coverages: Average debt/coverage ratios for Cogen 1 and 2 are 2 or greater (4 pts); CC2 and Bio 1 and 2 are around 1.5 (1 pt); Geo 1 and 2 and CC1 are less than 1.3 (0 pts).

16) Maintenance- O&M Contract: Assume all projects do not provide this contract; not included in PG&E wokshop project viability factors (0 pts).

17) Optional operating security: Assume all projects do not provide this contract; not included in PG&E project viability factors (0 pts).

Operational Factors

18) Unit commitment: We assumed that plants that offer man. dispatch have commitment on daily/wkly basis (14 pts); plants that offer 1500 hrs have commitment on weekly basis (6 points).

19) Economic Dispatch: Geo and Cogen offer 1500 hours of curtailability. We assumed that this is equivalent to partial dispatch (8 pts); CC and Bio offer manual dispatch, so get maximum points (20).

20) Automatic Generation Control: No projects offered auto gen. control in PG&E workshop (not an option); 0 points.

21) Black-start: Assume all projects require off-site power (0 pts).

22) Location: Assume CC, Cogen and Bio are in area 1 (4 pts); Geo is not, assume area 3 (1 pt); environmental constraints on project location.

23) Unit size: Bio is 15 MW (3 pts); Other projects are > 40 MW (0 pts).

24) Fuel diversity: CC and Cogen are gas (4 pts); Bio is waste (8 pts); We assume tha geothermal project is treated as coal project for purposes of valuing fuel diversity (6 pts).

25) Fuel flexibility: We assume that CC and Cogen, and Biomass can burn 2 fuels (bio can burn wood and coal) - (6 pts); Geothermal has no multiple fuel capability (0 pts).

26) Quick start ability: Assume CC has quick start (5 points); other projects do not (0 points).

Environmental Factor

27) Environmental Rating: We used NMPC's rating sheet and awarded points for all four technologies for relative environmental impact in various areas: transmission, fuel delivery, cooling water, emissions, terrestial, noise, vision, land use, solid waste. We worked with QF consultant to make subjective judgments; it was more important for us to get proper emphasis on relative impact of each technology, rather than points on an absolute scale. Table on environmental rating is included in Appendix F; Geothermal was treated as a proxy for coal plant in terms of measuring environmental impacts; Geothermal received fewer points than other three technologies.

28) Environmental Benefit: Assume all projects do not provide additional public access or recreation facilities and no additional environmental mitigation (0 pts).

Table F-4. Project bid scores in Boston Edison's bid evaluation system

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas-fired Cogen #1	Gas-fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	100	17	15	0	7	14	15	33	31
Economic Confidence Factors									
Breakeven Period	30	20	30	8	15	17	30	30	27
Front Load Security	20	0	20	0	0	0	20	20	20
Project Development Confidence Factors									
Tech./Environ. Feasibility	10	10	10	10	10	10	10	9	9
Project team experience	6	6	6	6	6	6	6	2	2
Level of Development									
Siting	10	10	10	10	10	0	0	0	10
Design & Engineering	4	2	2	2	2	2	2	2	2
Permit & Licensing	6	3	3	3	3	3	3	3	3
Financing	6	4	4	4	4	4	4	4	4
Thermal Energy	2	0	0	0	0	2	2	2	2
Construct./Oper.	2	0	0	0	0	0	0	0	0
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Operational Longevity Confidence Factor									
Debt & Operating Coverages	6	0	0	4	4	0	0	1	1
Fuel Supply	6	0	0	0	0	0	0	0	0
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
System Optimization Factor									
Dispatchability/Interruptibili	10	10	10	8	8	8	8	10	10
Fuel type	10	0	0	0	0	4	4	8	8
Size	2	0	0	0	0	0	0	2	2
Location	4	4	4	4	4	0	0	4	4
Maintenance Scheduled by BECo	4	4	4	4	4	4	4	4	4
PRICE FACTORS	100	17	15	0	7	14	15	33	31
NON-PRICE FACTORS	150	73	103	67	70	60	93	101	112
TOTAL	250	90	118	67	77	74	108	134	143

	Mean	Std. Dev
PRICE FACTORS	16.5	10.3
NON-PRICE FACTORS	84.9	18.4

Notes on Table F-4: Scoring Bids in BECO's bid evaluation system.

Price

1) Price Factor: 100 points for zero % of avoided cost; 100 - % of avoided cost gives price score.

Economic Confidence Factors

2) Breakeven Period: Five projects have some front-loading; we calculated break-even periods by adding yearly PV of benefits for all three scenarios until year in which it became positive.

3) Frontload security: Two projects posted failure security as cash equivalent (Cogen #1 and Bio #2); we calculated % that security represented of cumulative overpayment.

Project Development Confidence Factors

4) Technical/Environmental Feasibility: Biomass has 80% availability (9 pts); Other projects > 85% so get 10 pts.

5) Project team experience: Biomass has less development experience (similar scale but not of similar type), so get 2 points vs. 6 pts for other projects.

6) Siting: CC, Cogen, and Biomass#1 purchased firm site control (increased capital cost by 1%), they get 10 points; Geothermal and Biomass#2 have no firm site control (0 points).

7) Design and Engineering: Assume all projects are detailed (2 pts).

8) Permit and Licensing: All projects have identified req'd permits so get 3 points.

9) Financing: Assume all projects have 50% of required capital committed, so get 3 points.

10) Thermal Energy: Geo and Biomass are renewable QFs (2 pts); Others receive 0 pts.

11) Construction/Operations: Projects not under construction, so receive 0 points.

12) Additional Contract Deposit: Cogen #1 and Bio#2 purchased project failure security in cash; 500k and 300k respectively, which is greater than $7.50/kW additional deposit, so get 4 points; other projects receive 0.

Operational Longevity Confidence Factor

13) Debt and Operating Coverage: Avg. debt coverages =2.5 (6 pts); 2.0 gets 4 pts; 1.5 gets 1 pt.

14) Fuel Supply: All projects have fuel supply and transport plan (met threshhold requirement only); so get 0 points.

15) Maint. O&M contract: Not a category in original project viability options for PG&E workshop; assume 0 points.

16) Operation security: Not a category in original project viability options for PG&E workshop; assume 0 points.

System Optimization Factor

Dispatchability/Interruptibility: CC and Biomass offer manual dispatch (10 pts); Geo and Cogen offer 1500 hrs curtailable (we'll give 8 points for top interruptible).

18) Fuel Type: CC and Cogen are other (0 pts); Bio is waste (8 pts); Assume Geo is Coal for additional fuel diversity benefit (4 pts).

19) Size: Bio is 15 MW (2 pts); Other projects are >40 MW (0 pts).

20) Location: Assume CC, Cogen and Bio are in Area 2 (4 pts); assume Geothermal is not in area 1,2, or 3 because of environmental constraints (0 pts).

21) Maint. schedule operated by BECo: All projects have bid 1500 hrs of curtailable power or manual disp. which is more control than maint. control required by BECo (assume 4 pts).

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