BEFORE THE

RHODE ISLAND PUBLIC UTILITY COMMISSION

DOCKET NO. 4185

REVIEW OF THE AMENDED POWER PURCHASE AGREEMENT BETWEEN NARRAGANSETT ELECTRIC D/B/A NATIONAL GRID AND DEEPWATER WIND BLOCK ISLAND, LLC PURSUANT TO R.I.G.L § 39-26.1-7

DIRECT TESTIMONY

OF

ROBERT McCULLOUGH

ON BEHALF OF THE CITIZEN INTERVENERS GROUP

July 20, 2010

Q. Please identify yourself for the record.

A. My name is Robert McCullough. I am the Managing Partner of McCullough Research, 6123 S.E. Reed College Place, Portland, Oregon 97202.

Q. On whose behalf are you testifying?

A. The Citizen Interveners Group.

Q. Can you summarize your experience and qualifications?

A. Yes. I have been active in the electricity business for the past thirty years. I started as a manager for rates in 1979 at Portland General Electric. Over the next decade I was steadily promoted until I reached the rank of Vice President in PGE's power marketing subsidiary. In 1991 I left PGE to found McCullough Research, a consulting firm concentrating on bulk power issues. Over the last twenty years I have advised energy buyers, utilities, governments, and regulators on energy contracting issues from Quebec to California. My testimony at the U.S. Senate concerning Enron's energy trading in 2002 initiated the investigation of its trading practices by FERC, the CFTC, and the U.S. Department of Justice. We worked for the DOJ in the course of the Enron prosecutions. We also worked for the state attorney generals of California, Oregon, and Montana on related issues.

Q. What is your background on energy contracts and procurement?

A. Extensive. I have advised utilities, companies, and governments about power supply issues in jurisdictions across the U.S. and Canada. My detailed curriculum vita is attached as Exhibit RM-1 to this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The Citizen Interveners Group asked me to review the National Grid Deepwater Wind transaction for consistency with the "commercially reasonable" standard as set out in R.I.G.L § 39-26.1-7.

Q. What does the recently enacted statute say about "commercially reasonable"?

A. The statute states:

> (c) The commission shall review the amended power purchase agreement taking into account the state's policy intention to facilitate the development of a small offshore wind project in Rhode Island waters, while at the same time interconnecting Block Island to the mainland. The commission shall review the amended power purchase agreement and shall approve it if:

> (i) The amended agreement contains terms and conditions that are commercially reasonable;

The statute further clarifies the definition of "commercially reasonable" in Section (c)(iv):

> Notwithstanding any other provisions of the general laws to the contrary, for the purposes of this section, "commercially reasonable" shall mean terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see for a project of a similar size, technology and location, and meeting the policy goals in subsection (a) of this section.

Q. How did you approach this evaluation?

A. I approached this as a standard business review. I asked how reasonable the pricing was, how well documented the product was, and how well the transaction was written down.

Q. Can you characterize your conclusions?

A. If I had been retained to evaluate the transaction for either Deepwater Wind or National Grid I would recommend substantial changes. The price for Deepwater Wind is high – significantly higher than similar projects recently completed or currently underway in Europe.[1] Our knowledge of what we are actually purchasing is limited.[2] The cost figures give the appearance of being reverse engineered from a required rate of return rather than derived from basic engineering estimates.[3] The rate of return seems high with any reasonable level of leverage and due diligence by the purchaser was lacking. Finally, the proposed contract's pricing sections are poorly written and several other sections may contain drafting errors.

Q. Why do you characterize the contract price as high?

A. The electric industry in the U.S. has three different standards for evaluating resource acquisitions. These are:

1. Fully allocated cost;
2. Avoided cost;
3. Competitive market pricing.

[1] See, for example, Figure 7 in Support schemes for renewable electricity in the EU, European Commission Economic papers 408, April 2010, reproduced below.
[2] See, for example, Deepwater Wind's Response 1-13 to DPU's first request in Docket 4111.
[3] See, for example, Deepwater Wind's Response 1-4 to DPU's first request in Docket 4185. The reduction of $14 million from Docket 4111 expected cost has apparently had no impact on the pricing in Docket 4185.

The Deepwater Wind acquisition meets none of these standards. All parties agreed in Docket 4111 that the price is higher than cost, avoided cost, or market. I can think of no simpler test of whether the price is high compared to standard commercial standards.

Q. How does the price Deepwater Wind compare against similar projects?

A. Very poorly. In fact, the price received by Deepwater Wind is considerably above even the comparable project recommended by Deepwater Wind, itself.

Q. Why do you characterize the purchaser's due diligence as lacking?

A. The purchaser's responses to interrogatories in this docket speak for themselves:

> While National Grid does not have Deepwater Wind's current financial model, National Grid has reviewed that model with a representative of Deepwater Wind. This review included the cost estimates provided by Deepwater Wind, the projected returns for the project, and the bundled energy price ($/MWh) included in the Amended PPA, to determine that the calculations, including the table in Appendix X, are correct. In that table, the bundled energy price in the December 9, 2009 PPA corresponds to the price if the Total Facility Cost is greater than or equal to the Base Amount; additional costs above the Base Amount do not increase the bundled price; and incremental savings below the Base Amount reduce the bundled price. National Grid is not is [sic] a position to review and confirm the elements of cost that are contained in the financial model.[4]

National Grid, the purchaser of the resource, is "not is [sic] a position to review and confirm the elements of cost that are contained in the financial model." In any reasonable commercial transaction it is appropriate to conduct due diligence on the product being purchased.

A concern that an "experienced power market analyst" might raise is that the payment that National Grid will receive as part of this transaction has given the wrong incentive – rewarding National Grid for the purchase without exposing National Grid to sufficient risk if the transaction's price is excessive.[5]

Q. Are there problems with the contract drafting?

[4] Response to Division Data Requests – Set 1, Issued July 6, 2010, response to Request 1-3.

[5] R.I.G.L. 39-26.1-4, and State of Rhode Island and Providence Plantations Public Utilities Commission Docket No. 411 Errata Order

> Deepwater Indisputably has a great deal at stake, and Grid stands to receive approximately $19 million in statutorily-authorized "remuneration" payments just for signing the PPA, assuming the Project produces

A. Yes. The pricing language is opaque and difficult to interpret. In addition, there appears to be several substantive errors in the version proposed for approval in the instant hearing. In addition, there are minor errors which simply give the impression that the contract has not been sufficiently proofed.

This is an expensive project. Deepwater Wind is new to offshore wind projects. Capitalization and financing is unknown. All these are reasons to make the contract as iron clad as possible.

Q. Overall, how would you characterize this contract?

A. This contract is not commercially reasonable. The prices are high, the due diligence has not been completed (perhaps more accurately, even initiated), and the contract has a number of serious flaws. If I had been retained by either of the counterparties I would have recommended significant changes.

The scenario is akin to a purchaser buying a house through a real estate agent. The price is higher than comparable transactions, the agent is receiving a commission on the transaction, no inspection of the house has been undertaken, the creditworthiness of the seller is suspect, and the real estate contract is poorly written with a number of obvious errors.

Contract Price

Q. Why do we need to review the cost of this project?

A. If National Grid planned to purchase the project and resell it into the market, we would not have to review the pricing. National Grid would be taking the risk that the pricing was inappropriate. The situation here is very different. As an electric distributor, National Grid is acting as an agent for ratepayers and receiving a substantial payment for providing this service. Discovery indicates that National Grid has not exercised extensive due diligence in this matter, so it is incumbent upon the Commission to protect ratepayers by checking whether this is a commercially reasonable – one might even say "prudent" transaction.

Q. Is there anything new about this situation?

A. No. This review is built into the very fabric of the traditional utility model. The utility has an incentive to build the best possible system since it is remunerated on formulas based on investment and expense. Over time we have evolved three different cost standards: fully allocated cost, avoided cost, and market pricing.

Fully Allocated Costs

Q. How did you evaluate this project on a fully allocated cost basis?

A. I would follow the same basic steps as those presented by the Commission staff in Docket 4111. Their approach was to question whether the project generated unreasonable rates of return for the sponsor. Given the relatively small amount of information on the ownership structure and financing, this is not an easy job.

Q. Who actually owns this project?

A. Based on the limited information available as of May 14, 2010 approximately three quarters of Deep Water Wind Holdings, LLC. was beneficially owned by a hedge fund named D. E. Shaw. A minority of the project is owned by First Wind Holdings, LLC.[6] D. E. Shaw also has a major ownership position in First Wind Holdings.[7]

Q. How does this affect the economics of the project?

A. Projects like Deep Water Wind are often financed through a framework of special purpose entities (SPEs) designed to capture tax benefits and take advantage of leverage. There has been some discussion in Docket 4111 concerning whether Deepwater Wind would have the capability to take advantage of these opportunities. Clearly, its ownership by a major hedge fund with $21 billion in investments and committed capital indicates that the benefits of structured finance are readily available. This is not a small company with limited abilities to approach markets for tax monetizations. Since Deepwater Wind Block Island LLC is a tax pass-through entity, any and all of its tax loses and other tax assets are available to its parent, Deepwater Wind Holdings and other tax pass-through affiliates. While this may or may not be the case, Deepwater's parent company, its affiliates, and/or its beneficial owners will be able to do so due to the tax passthrough status of its contract party under the Amended PPA.

Q. What capital structure is Deepwater Wind likely to use?

[6] Amendment No. 6 to FORM S-1 REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933 of First Wind Holdings Inc., May 14, 2010, page 159.

> On May 2, 2008, we received voting interests in Deepwater Wind Holdings, LLC, a wind energy development company focused on developing wind energy projects offshore the continental United States, in exchange for a contribution of $3.4 million in cash and other assets with a net book value of approximately $471,000. We and the D. E. Shaw Group currently own approximately 13.6% and 72.1%, respectively, of the outstanding voting interests in Deepwater Wind Holdings, LLC, with the balance of the membership interests held by third-party investors.

[7] Ibid., page 7.

A. Discovery indicates that the debt/equity ratio will be on the order of 80/20.[8]

Q. How does this affect the internal rate of return for the project?

A. If the unleveraged return is higher than the cost of debt, which it is in this case, the financial benefits for the developer are very significant. Let's take a simple example:

Unleveraged return on equity:	10.5%[9]
Cost of debt:	6.5%[10]
Leveraged return on equity:	26.5%[11]

Q. Please review Mr. Moore's statement:

> Deepwater Wind believes that the proper reference point for considering an appropriate projected rate of return is the project-level, or unlevered, rate of return, which does not take into account debt financing and associated tax consequences, such as tax benefits resulting from interest expenses, because to do so at this point in time would be a purely hypothetical exercise. The rationale is simple.[12]

Do you agree with this statement?

A. No, Mr. Moore's statement is particularly ironic since it is the timing of the Section 48 Investment Tax Credit grant which is apparently dictating the schedule for this project.[13]

Q. Have you reviewed the testimony of Mr. Pasqualini in his testimony in Docket 4185 that the long construction period envisaged for Deepwater Wind may make it impossible to find a tax equity investor?

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[8] Response to Division Data Requests – Set 1, Issued December 31, 2009, response to Request 1-18.
[9] Direct testimony of William H. Moore, Docket 4185, page 14.
[10] New York's Offshore Wind Energy Development Potential in the Great Lakes, NYSERDA, April 2010, page 158.
[11] Actual ROE = (Unleveraged ROE – 80% x Cost of debt))/20% Equity.
[12] William M. Moore Rebuttal Testimony, Docket 4111, Page 1.
[13] See for example, his comments on page 10:

> Under current rules, wind projects must make certain equipment purchases in 2010 in order to take advantage of the Section 1603 program through 2012. This is Deepwater Wind's current plan, and why it is important to have the PPA approved soon so it can take the next step of making financial commitments on equipment contracts. By doing so, Deepwater Wind will take a step in the direction of ensuring that the Block Island Wind Farm qualifies for this important Federal incentive.

A. Yes. In 2007 the Ernest Orlando Lawrence Berkeley National laboratory issued a useful monograph on this topic entitled "Wind Project Financing Structures: A Review & Comparative Analysis."[14] It provides a very cogent introduction for seven models of structured financing vehicles for wind power. The monograph has a variety of decision matrices (shown below) to guide prospective developers and their financial advisors through various options:[15]

Scenario	Developer can use Tax Benefits	Developer can fund project costs	Developer wants to retain stake in project ownership / ongoing cash flows	Developer wants early cash distributions	Project has low projected IRR	Project already exists (refinancing / acquisition)	**Most suitable financing strategy or structure:**
1	No	No	No	Yes	N/A	No	**Sell project to a Strategic Investor**
2	Yes	Yes	Yes	No	No	No	**Corporate**
3	No	Limited	Yes	No	No	No	**Strategic Investor Flip**
4	No	Limited	Yes	Yes	No	No	**Institutional Investor Flip**
5	No	Limited	Yes	No	Yes	No	**Cash Leveraged *or* Cash & PTC Leveraged**
6	No	Limited	Yes	Yes	No	Yes	**Institutional Investor Flip**
7	No	Yes	Yes	Yes	N/A	Yes	**Pay-As-You-Go**
8	No	Limited	Yes	Yes	Yes	No	**Back Leveraged**

The timing of construction does not appear in this matrix, nor has the timing of construction appeared in discussions I personally have been involved in other projects.

Q. Has Deepwater Wind or its owners explained their financing plan in any detail?

A. No.

Q. Can you describe your recommendation on the basis of fully allocated costs?

A. This is not a commercially reasonable transaction. Basic questions first asked in the RFP have not been answered. In the next section I note three areas where questions were answered, the answers themselves are in flux.

Avoided Costs

Q. Should the evaluation of this project have been subject to National Grid's avoided cost filings?

[14] Wind Project Financing Structures: A Review & Comparative Analysis, John P. Harper, Birch Tree Capital, LLC Matthew D. Karcher, Deacon Harbor Financial, L.P. Mark Bolinger, Lawrence Berkeley National Laboratory, September 2007.
[15] Ibid., page 37, for example.

A. Yes. This has been the standard for resource acquisition by utilities since 1979. The strongest argument for PURPA (Public Utility Regulatory Policies Act) pricing is that it is a level playing field. If National Grid actually felt that this was a commercially reasonable transaction, they would have allowed a variety of alternatives to be brought forward – not just one.

Q. How does this compare to National grid's filed avoided costs?

A. Deepwater Wind's price is very high compared to the avoided costs filed by National Grid in New York, New England, and Rhode Island:

(1) Rhode Island -- Narragansett Electric Company d/b/a National Grid:
"Company will pay rates equal to the payments received by the Company for the sale of such qualifying facilities' output into the ISO-NE administered markets for the hours in which the qualifying facility generated electricity in excess of its requirements."[16]

Effective Date: September 14, 2009

(2) New York -- Niagara Mohawk Power Corporation d/b/a National Grid:
Energy: NYISO Real-Time Generator Bus LBMP * Quantity - Incurred Costs ("NYISO Automatic Generation Control Penalties")

Energy + Capacity: (NYISO RT LBMP * Quantity - Incurred Costs) + (Monthly LBMCP * Monthly Capacity)[17]

Effective Date: April 27, 2009

(3) Massachusetts -- Massachusetts Electric Company d/b/a National Grid:
Company will pay "rates equal to the payments received by the Company from the ISO power exchange for such output for the hours in which the QF generated electricity in excess of its requirements."[18]

Effective Date: May 1, 2001

(4) Massachusetts -- Nantucket Electric Company d/b/a National Grid:
Company will pay "rates equal to the payments received by the Company from the ISO power exchange for such output for the hours in which the QF generated electricity in excess of its requirements."[19]

[16] Narragansett Electric Company Rates Tariff, R.I.P.U.C No. 2035.
[17] Niagara Mohawk Power Corporation Rates Tariff (PSC No: 220), Service Classification No. 6.
[18] Massachusetts Electric Company Rates Tariff, M.D.T.E. No. 1032-C.
[19] Nantucket Electric Company Rates Tariff, M.D.T.E. No. 1032-C.

Effective Date: May 1, 2001

(5) New Hampshire -- Granite State Electric Company d/b/a National Grid:

Energy Rates by Voltage Level (cents/kWh):[20]

Voltage Level	Peak Period	Off-Peak Period	Average
(1) Subtransmission	3.697	2.965	3.303
(2) Primary Distribution	3.971	3.111	3.508
(3) Secondary Distribution	4.111	3.184	3.612

Capacity Rates by Voltage Level:

Voltage Level	$/kW Year	$/kW Month
(1) Subtransmission	$27.80	$2.32
(2) Primary Distribution	$30.44	$2.54
(3) Secondary Distribution	$31.84	$2.65

Effective Date: January 1, 1998

Q. Are these close to the prices asked under this contract?

A. No. There is a large disparity between prices in this contract and the avoided costs filed by National Grid.

Market Pricing

Q. What are comparable market prices to this project?

A. This is a very interesting question. Unlike Western Europe, the United States and Canada occupy a vast continent with immense wind potential. Logically, the best locations would be developed first. Since off-shore wind costs over twice that of land based wind – and this project costs three to four times comparable land based projects – market forces have not rushed towards off-shore projects.

Q. Are there any comparable projects?

A. There are a number of comparable projects identified in the NYSERDA study published this spring.[21] A number of parties in Docket 4111 as well as the instant docket have cited Table 10.1 on page 153:

[20] Granite State Electric Company Rates Tariff, N.H.P.U.C. No. 17

Project Name	Country	Status	Operating Year	Project Cost ($M)	Project Capacity (MW)	Project Cost per MW ($M)	No. Turbines	Turbine Size (MW)	Turbine Model	Water Depth (m)	Distance from Shore (km)
Middelgrunden	Denmark	Commissioned	2001	$ 51	40	$ 1.28	20	2	Bonus 2 MW	5 to 10	2 to 3
Horns Rev	Denmark	Commissioned	2002	$ 295	160	$ 1.84	80	2	Vestas V80	6 to 14	14 to 17
North Hoyle	United Kingdom	Commissioned	2003	$ 138	60	$ 2.30	30	2	Vestas V80	5 to 12	7.5
Nysted	Denmark	Commissioned	2004	$ 316	165.6	$ 1.91	72	2.3	Siemens 2.3	6 to 10	6 to 10
Scroby Sands	United Kingdom	Commissioned	2004	$ 136	60	$ 2.27	30	2	Vestas V80	2 to 10	3
Kentish Flats	United Kingdom	Commissioned	2005	$ 179	90	$ 1.98	30	3	Vestas V90	5	8.5
Barrow	United Kingdom	Commissioned	2006	$ 172	90	$ 1.91	30	3	Vestas V90	15	7
Burbo Bank	United Kingdom	Commissioned	2007	$ 170	90	$ 1.89	25	3.6	Siemens 3.6	10	5.2
Egmond aan Zee	Netherlands	Commissioned	2007	$ 300	108	$ 2.77	36	3	Vestas V90	17 to 23	8 to 12
Inner Dowsing	United Kingdom	Commissioned	2008	$ 289	97.2	$ 2.97	27	3.6	Siemens 3.6	10	5.2
Lillgrund	Sweden	Commissioned	2008	$ 254	110.4	$ 2.30	48	2.3	Siemens 2.3	2.5 to 9	10
Princess Amalia	Netherlands	Commissioned	2008	$ 582	120	$ 4.85	60	2	Vestas V80	19 to 24	> 23
Alpha Ventus	Germany	Commissioned	2009	$ 350	60	$ 5.83	12	5	Multibrid & REpower	30	45
Gunfleet Sands I	United Kingdom	Commissioned	2009	$ 406	108	$ 3.76	30	3.6	Siemens 3.6	2 to 15	7
Horns Rev Expansion	Denmark	Commissioned	2009	$ 854	209.3	$ 4.08	91	2.3	Siemens 2.3	9 to 17	30
Rhyl Flats	United Kingdom	Commissioned	2009	$ 358	90	$ 3.98	25	3.6	Siemens 3.6	8	8
Robin Rigg	United Kingdom	Commissioned	2009	$ 651	180	$ 3.62	60	3	Vestas V90	>5	9.5
Sea Bridge	China	Under construction	2010	$ 345	102	$ 3.38	34	3	Sinovel 3 MW	8 to 10	8 to 14
Gunfleet Sands II	United Kingdom	Financing secured	2010	$ 275	64.8	$ 4.24	18	3.6	Siemens 3.6	2 to 15	7
Nordergrunde	Germany	Financing secured	2010	$ 440	90	$ 4.89	18	5	REpower 5M	4 to 20	30
Walney	United Kingdom	Financing secured	2010	$ 746	151.2	$ 4.93	42	3.6	Siemens 3.6	20	7
Belwind	Belgium	Financing secured	2011	$ 897	165	$ 5.44	55	3	Vestas V90	20 to 35	46
Thanet	United Kingdom	Financing secured	2011	$ 1,200	300	$ 4.00	100	3	Vestas V90	20 to 25	7 to 8.5
London Array	United Kingdom	Financing secured	2012	$ 3,095	630	$ 4.91	175	3.6	Siemens 3.6	23	>20
Sheringham Shoal	United Kingdom	Financing secured	2012	$ 1,500	316.8	$ 4.73	88	3.6	Siemens 3.6	16 to 22	17 to 23

I have highlighted the project Mr. David Nickerson has argued is the most similar to Deepwater Wind:

> The most similar project in this group is a German project called Alpha Ventus that reached full commercial operation in April 2010. It is a demonstration project consisting of twelve, 5 MW wind turbines from two different turbine vendors. Six of the twelve turbine foundations are the jacket type that are likely to be used for the Block Island Wind Farm. I consider this to be similar in "technology", with one necessary adjustment, which is described later. The project is located in water 30 meters deep – effectively the same "location" as the Block Island Wind Farm. Only the "size" at 60 MW is different. However, it is the closest project in size in the data set.[22]

Q. Why has Mr. Nickerson singled out Alpha Ventus?

A. He states:

[21] New York's Offshore Wind Energy Development Potential in the Great Lakes: Feasibility Study, NYSERDA, April 2010.

[22] Direct testimony of David Nickerson, Docket 4185, July 15, 2010. Pages 5 and 6.

> The primary focus of my analysis is on installed cost, expressed in dollars per kilowatt ($/kW) of nameplate capacity. As I discussed in Docket 4111, a review of the key cost elements that impact the price and price structure in a long term PPA indicate whether the PPA pricing is reasonable and consistent with expectations. For offshore wind, the key cost elements are installed costs, ongoing operations and maintenance costs, and cost of capital (rate of return). If each of these underlying elements is reasonable, then it is consistent to conclude that the PPA pricing and the associated payment stream over time is reasonable, particularly in the context of the New PPA and its "open-book pricing" structure.[23]

Q. Is this a very common procedure?

A. No, it is very unusual indeed. In making a purchase I am most interested in the price, not the cost. When the salesman assures me that the vendor is losing his shirt on the transaction, I normally regard this as sales talk and nothing more. As with this transaction, I first look at the price, then check the performance, and finally review the purchase terms and conditions. This is particularly true in this situation where the "cost" of the project is somewhat hard to pin down.

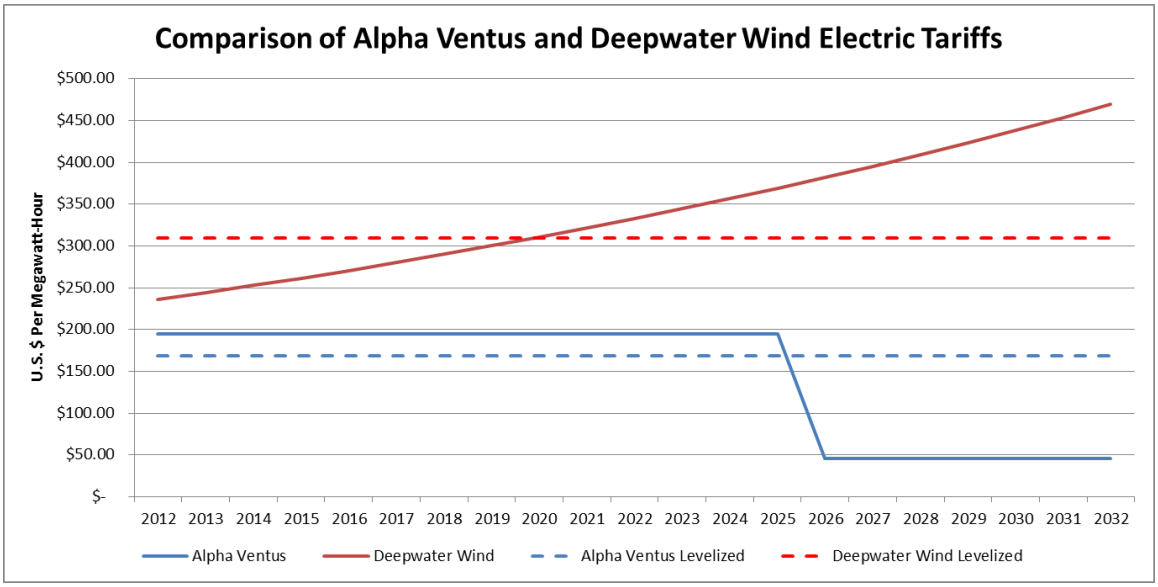
Q. Did Mr. Nickerson discuss the price Alpha Ventus is being paid?

A. Mr. Nickerson did not note that the price for energy for Alpha Ventus is considerably lower than the price being asked for Deepwater Wind in this docket.

Q. What is the levelized price for Alpha Ventus?

A. Using an 8% discount rate, the levelized price is $168.54. This compares to a levelized value of $309.04/MWh for Deepwater Wind. The following chart shows the prices for Alpha Ventus and Deepwater Wind:

[23] Ibid., page 6.



Q. How were the prices for Ventus Wind derived?

A. Germany, like many members of the European Economic Community sets a "Feed-In Tariff" or FIT for renewable energy projects. The Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz / EEG) regulates the feed-in power tariff in Germany. This law was adopted in 2000 and amended in 2004 and 2008.[24] The initial tariff for offshore wind energy is €13 per MWh for a period of 12 years (+ €2 per MWh for all turbines installed before year end 2015). The tariff period is extended before reduction to a base level for deeper waters and greater distances from the land.

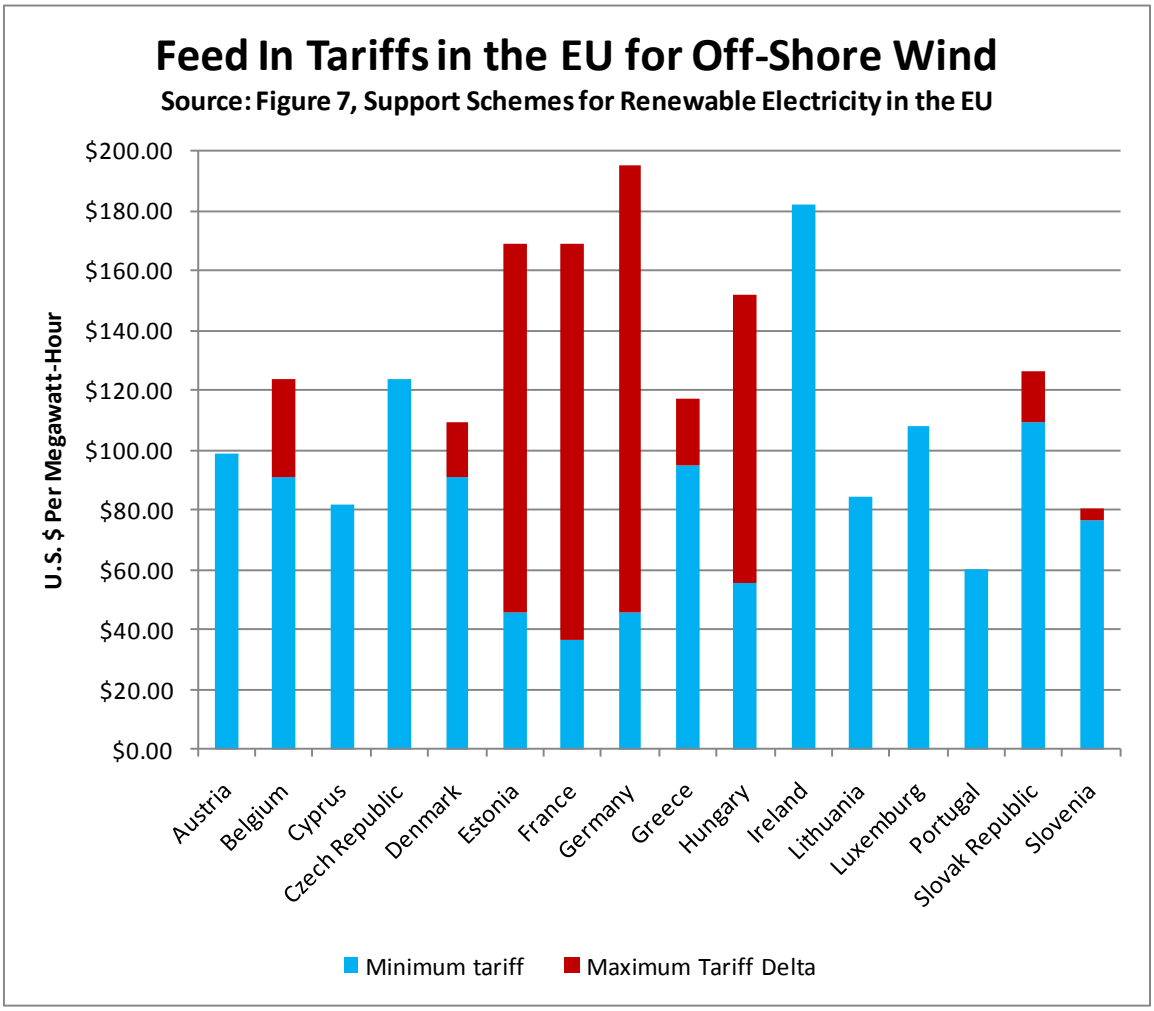
Q. Is the German Renewable Energy Sources Act unusual?

A. Not at all. Europe has adopted FITs in many different countries. Programs differ from nation to nation, however. A useful monograph has recently been released on the off-shore prices in the EEC named "Support schemes for renewable electricity in the EU."[25]

Q. Are European Feed In Tariff's lower than the proposed price for Deepwater Wind?

A. Yes. Figure 7 summarizes Feed In Tariffs by technology across the EU. I have reproduced their table here, using U.S. dollars per MWh for the convenience of the Commission:

[24] About Offshore Wind Energy in Germany, Frank B. Hawn, September 2008.
[25] Support schemes for renewable electricity in the EU, European Commission, Joan Canton and Åsa Johannesson Lindén, March 26, 2010.



Q. Is this the only source on European FITs?

A. No. There is an extensive literature on the subject. This monograph is significant because it is from an impartial source and was recently published. A second interesting monograph was published in 2007 by KPMG.[26]

[26] Offshore Wind Farms in Europe, KPMG, 2007. Their comparable table of FITs can be found on page 7:

Q. What proportion of the projects identified in Table 10.1 of the NYSERDA is from counties in the European Union?

A. The table has 25 entries. One project is from China. This means that 92% of the projects cited would be subject to tariffs set in the EU. The United Kingdom accounts for 14 of the projects. Great Britain has a complex system of its own, but has recently begun to adopt the Feed-In Tariff approach as well.

Q. How precisely has Deepwater Wind researched comparable projects?

A. They have apparently depended on the survey by NYSERDA cited above. While the survey is good, it is not as comprehensive as it could be. Within the time limits of Docket 4185, I have conducted a survey of 158 off-shore wind projects either now in service or currently under development. This survey is reproduced as Exhibit RM-2 to this testimony. Within this dataset, five projects meet the criteria of either having been recently placed in service or now being developed as well as having nameplate ratings between 20 and 60 megawatts.

Q. Why did you choose the range of 20 megawatts to 60 megawatts?

A. I followed Mr. Nickerson's selection of 60 megawatts in order to include his comparable wind farm, Alpha Ventus. The lower limit was chosen to be slightly lower than Deepwater Wind's projected capacity.

Overview of Feed-in tariff systems in Europe

Country	Current tariff ct/kWh	Duration	Subsidies	Grid connection	Tax relief
Denmark	6.95 (Horns Rev II)	50,000 full load hours	–	✓	–
Germany	9.1	12 years/20 years	–	✓	–
France	Initially 13.0 then 3.0 – 13.0	Both phases 10 years each	–	–	✓
Great Britain	13.49	Certificates up to 2027	✓	–	✓
The Netherlands	MEP tariff stopped	Not covered at present	Not covered at present	Not covered at present	Not covered at present
Sweden	6.19	Certificates 15 years/ bonus up to 2009	✓	–	–
Spain	12.03 (max. 16.4)	20 years	–	–	–

Q. **Which comparable plants have you identified in your survey?**

A. I have identified five offshore wind farms. The projects are in Belgium, Denmark, Germany, and the United Kingdom:

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth (m) min	Depth max	In Service Date	Country	Feed-in Tariff Minimum $/MWh	Feed-in Tariff Maximum $/MWh	Addition To Market?
Alpha Ventus	60	12	56	28	30	2010	Germany	$ 45.50	$ 195.00	No
Baltic 1	48	21	16	16	19	2010	Germany	$ 45.50	$ 195.00	No
Geofree	25	5	19	20	21	2012	Germany	$ 45.50	$ 195.00	No
Sprogo	21	7	10.6	6	16	2009	Denmark	$ 91.00	$ 109.20	Yes
Thornton Bank I	30	6	27	13	19	2009	Belgium	$ 70.00	$ 123.50	Yes

Q. How do we know what prices are paid for these projects?

A. Our best estimates depend on finding projects with national tariffs in place. Germany, as described above, has a very straightforward tariff. Belgium and Demark also have FITs, although their tariffs are of a slightly different format where the FIT is in addition to spot prices.

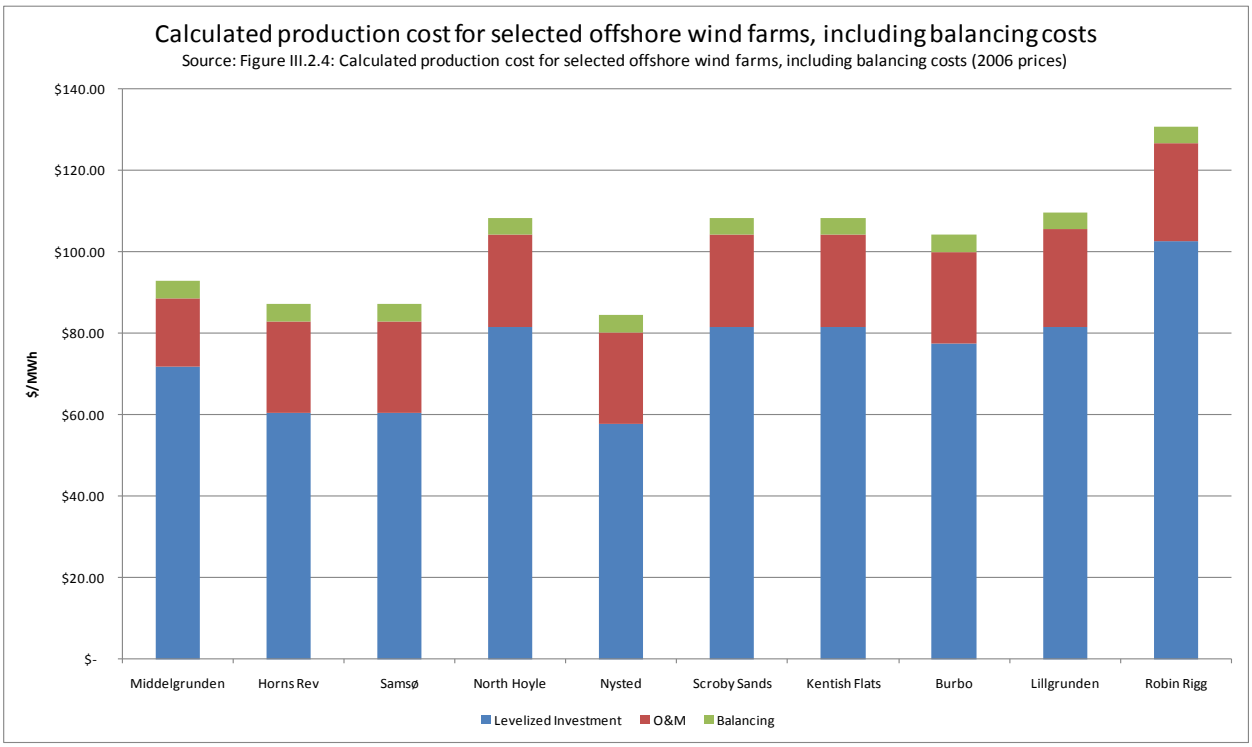
Q. In Denmark and Belgium the FIT is in addition to market prices. What levels are these likely to be?

A. Forecasting energy prices is challenging. Forecasting energy prices in several foreign countries is especially challenging. I have looked for current forecasts using models I have some familiarity with. Aurora forecasts indicate a range for base prices are in the range $65/MWh today through $120/MWh in 2030.[27] Given these forecasts, total prices paid to off-shore wind in Europe are still considerably less than the prices requested by Deepwater Wind.

Q. Have you found any estimates of actual production costs?

A. Yes. In a few rare cases we have estimates of their production costs. North Hoyle and Scroby Sands, for example, were analyzed as part of a study conducted in 2009.[28] These plants are of comparable size to our sample, but went into service some years ago. The following chart reproduces the conclusions of that study in 2010 dollars:

[27] See, for example, Modelling European Electricity Markets, Stephan Sharma, October 19, 2009.
[28] Wind Energy – The Facts, AWEA et al, February 2009, page 219.



Due Diligence

Q. What is "due diligence"?

A. This term describes the common sense review of the facts required before entering into a major transaction. A reasonable home owner has a home inspection conducted prior to completing the purchase. This is an everyday form of due diligence. The standards of due diligence increase as the price tag increases.

Q. What level of due diligence has been undertaken by National Grid?

A. A year ago it would have appeared that National Grid was proceeding in a normal fashion. The RFP issued included a number of "Bidder Response Forms" that would provide a description of the project under tender, its design, cost, maintenance, and financing. These submitted documents are now overtaken by events since the project has changed size, design, and ownership. As previously noted, National Grid states that it has done little in reviewing the costs of the project.

Q. How well is the project described in the proposed contract?

A. Without any exaggeration, Exhibit A, the description of the facility, is sketchy:

> EXHIBIT A
>
> DESCRIPTION OF FACILITY
>
> Facility: The Facility will be a wind generating facility to be located in the waters off the coast of Block Island, Rhode Island. The Facility will have no more than eight wind turbines, and the nameplate capacity of the Facility will be no more than thirty (30) MW.
>
> This Exhibit A will be supplemented with the Operational Limitations prior to Commercial Operation.

Q. Is this sufficient?

A. No. I would expect the equipment and its nameplate rating to be identified.

Q. What level of due diligence would you consider to be sufficient?

A. One would expect a utility to know the exact technology, equipment, and operational characteristics. Ownership and creditworthiness are also minimum standards. An excellent example of due diligence is the final report prepared for the Great Lakes Energy Development Task Force.[29] Contrary to assertions that financial structure should not be considered, the Final Feasibility Report has an extensive set of calculations showing the impact of leverage on economic feasibility.[30]

Q. Can you describe this document?

A. Yes. This pre-procurement document of 424 pages details the technology, industry, cost, contracting, financing, and market for off-shore wind on the Great Lakes. For example, Section 11 – fully 52 pages on project economics – contains vastly more information on the proposed Lake Erie project than anything from National Grid or Deepwater Wind in Docket 4185.

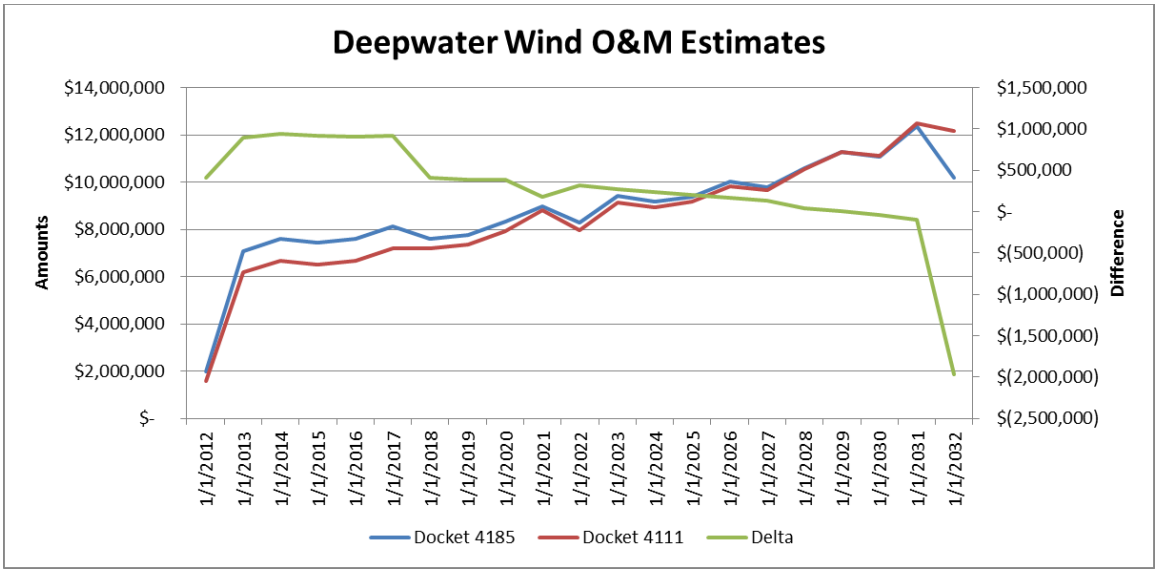
Q. How comfortable are we with the various numbers provided by Deepwater Wind?

A. It is difficult to be very comfortable with the materials they have provided so far. Two examples from the most recent pro forma make the shifting nature of their calculations apparent:

[29] Great Lakes Wind Energy Center Feasibility Study Final Feasibility Report, Barbi Driedger-Marshall et al, April 2009 at http://development.cuyahogacounty.us/pdf_development/en-US/GLWEC_Final%20Feasibility%20Report_4-28-09.pdf

[30] See, for example, Sections 11.2.7.3, 11.2.7.4, and 11.2.7.7.

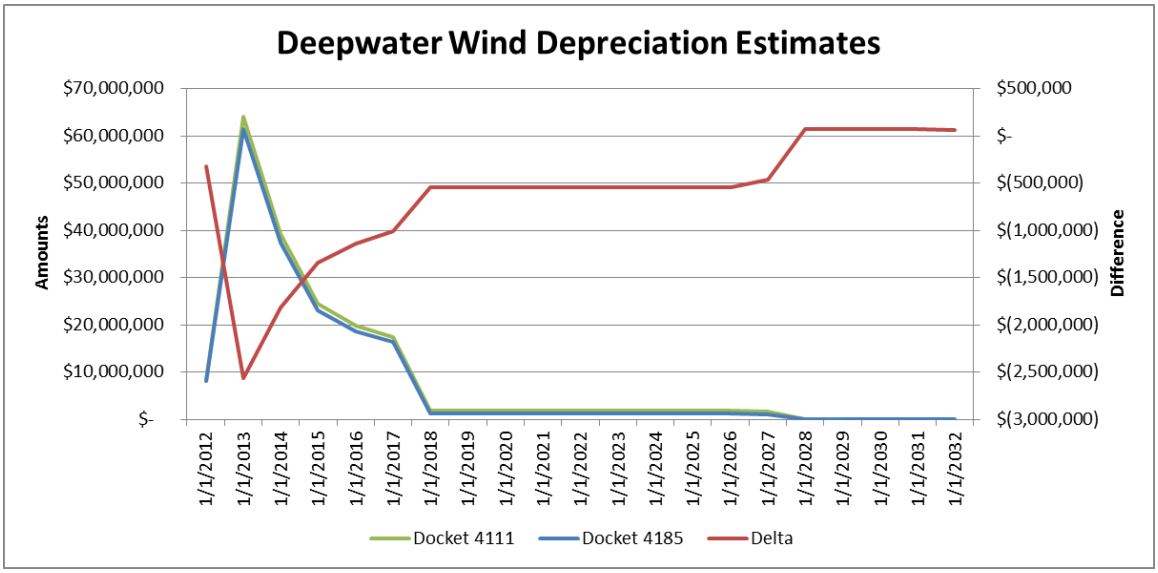
Docket 4111 contained testimony concerning the relatively high O&M values. Deepwater wind responded that these were solid estimates from a respected source.[31] Notwithstanding this response made only several months ago, the O&M numbers have increased significantly in the current pro forma:



Deepwater Wind's testimony did not address these changes. This undocumented increase in O&M would add .5% to the unleveraged return and over 1% to the leveraged return if eliminated from the calculations.

Similarly, the timing of depreciation has changed since Docket 4111:

[31] Rebuttal testimony of William H. Moore, Docket 4111, page 11.



Q. Are these changes legitimate?

A. It is impossible to know since the originals were undocumented and the new values are undocumented.

Q. What is the cost of Deepwater Wind?

A. This is an intriguing question. The cost in Docket 4111 was $219,311,412. The cost in Docket 4185 is $205,403,512. Deepwater Wind's response to a request to justify the difference was:

> The following differences reconcile the difference between the Docket 4111 Estimate and the Base Amount.
>
> (1) The contingency in the Docket 4111 Estimate has been reduced. This reduction results from a combination of factors. First, since the date of the development of the Docket 4111 Estimate last fall, Deepwater Wind has been engaged with various vendors and has done additional engineering of the facility. As a result, Deepwater Wind has removed various areas of uncertainty, and therefore Deepwater Wind's confidence in its estimates is greater than it was in the fall of 2009.
>
> (2) When Docket 4111 was pending, Deepwater Wind was still being considered for a Department of Energy Federal Loan Guarantee. Since the decision in Docket 4111, Deepwater Wind has been notified by the Department of Energy, that Deepwater Wind's application was not accepted. Accordingly, the financing

> costs of the facility that are in the Base Amount are higher than the financing costs in the Docket 4111 Estimate.[32]

Answer (1) indicated that the hitherto contingency amounts in the construction estimate have been reduced. Answer (2) indicates that the costs in Docket 4185 are larger than in Docket 4111 due to higher financing costs. The answer also contains a difficult to follow argument that the project cost is, in some fashion, dependent on the target unlevered return:

> The Base Amount, which is the measure against which realized savings are shared with the ratepayer, is approximately $14,000,000 less than the Docket 4111 Estimate. The Base Amount represents Deepwater Wind's estimate of a facility cost that Deepwater Wind projects will yield an acceptable unlevered return (approximately 10.5%) and a risk/return profile that will likely attract the financing necessary to construct the project.[33]

Q. Does this reassure you that we know the cost of this project?

A. No. Like Mr. Hahn, I am troubled that the cost of the project identified in the cost adjustment provision is now different than the cost used to develop the price of the project. It appears that the difference – approximately 10% of the total cost of the project has been reserved to increase profits from the project and may not represent costs at all.

Q. Is it necessary that the cost estimates be confused with the required rate of return for the project?

A. No. Deepwater Wind should provide a solid cost of the project and then justify a rate of return that would make it viable. These are separate issues and should be addressed as different parts of the analysis.

Q. Please characterize how commercially reasonable the current level of due diligence is on this project.

A. As previously stated, the due diligence has not been seriously undertaken by the buyer. Moreover, different estimates of the cost of the project have been changing without explanation or documentation. If I was advising the buyer in this transaction I would advise against going ahead without further verifiable information.

[32] Deepwater Wind Block Island, LLC Response to the Division of Public Utilities and Carriers' Data Request Div 1-4, page 2.
[33] Ibid., page 1.

Contract Language

Q. What is "contract failure"?

A. Contracts are an imperfect statement of the objectives of the counterparties at the time of signing. Any reasonably experienced businessperson is well-acquainted with just how imperfect even the best of intentions may be as a guide to the future. Contracts fail because the terms and conditions are not sufficient to deal with changing circumstances, changes in law or regulations, buyer's and seller's remorse, bankruptcy, and even issues of market manipulation.

In my review of the contract under discussion here, the standard of review – Section 19.5 – cited Morgan Stanley Capital Group Inc. v. Public Utility District Number 1 of Snohomish, Washington. This is a case that I have worked on for the past eight years, and is possibly the most famous example of contract failure in the history of the electricity industry.

In this case the contract failed due to revelations concerning the widespread market manipulation during the period when the contract was signed and the possible involvement of the seller, Morgan Stanley.

The Morgan Stanley transaction was approximately the same size as that under discussion here. The case has passed through FERC (Federal Energy Regulatory Commission) the Ninth Circuit Court of Appeals, and the U.S. Supreme Court, and presently awaits rehearing at FERC.

Q. Is there any reason to fear problems with this in the contract between National Grid and Deepwater Wind?

A. One always considers future problems. As I have noted, the technology is new to the seller, the prices are high compared to market, and little, if any, due diligence has been exercised by the buyer. In addition, this transaction could easily have problems with bankruptcy, delay, or regulatory changes.

Q. How would you characterize the billing language contained in Exhibit E?

A. The language is difficult to follow and likely to cause disputes in later years.

Q. Please give an example.

A. Section 3 states:

> Adjustment to Bundled Price for Forward Capacity Market Payments. Beginning in the fourth Contract Year, each monthly payment due to Seller under this Exhibit E will be reduced by the amount that Seller is or would have been

> eligible to receive in the ISO-NE Forward Capacity Market or any replacement market for capacity in ISO-NE, without regard to whether the Facility has actually qualified as a Capacity Resource in the Forward Capacity Market or whether the Facility has received a Capacity Supply Obligation for the Capacity Commitment Period during which the applicable billing period occurred. If the Facility has not qualified as a Capacity Resource or received a Capacity Supply Obligation for the relevant Capacity Commitment Period, Buyer shall calculate the reduction due under this Section 3 assuming that the Facility had qualified as a Capacity Resource and received a Capacity Supply Obligation, based on information obtained from Seller and publicly available information from ISO-NE, which calculation shall be binding, absent manifest error. Seller shall use commercially reasonable efforts to cooperate with Buyer in calculating this reduction.

Q. How would you interpret this section?

A. The buyer deducted the deemed capacity revenues from his payments to the seller. The New England ISO capacity markets have been highly controversial and it would appear that the risks of the capacity market have been left with the seller.

Q. Might there be different interpretation of this section?

A. Easily. There are detailed calculations involved in the determination of "Capacity" as noted above. Even if the two parties agree on the calculation of "Capacity", it is common for administered capacity markets to have different bidding options. Presumably, National Grid could deem a more successful bidding strategy for Deepwater Wind than it actually employed.

Q. How would you interpret the last sentence?

A. I cannot. It is effectively meaningless. I would have advised a fallback provision to other data at the New England ISO or a different solution to this problem entirely. Asking counterparties to calculate hypothetical "what if" cases is likely to be contentious. A similar provision in the power contracts of the Bonneville Power Administration has been litigated for almost thirty years.[34]

Q. Can you point out any serious problems with this contract?

[34] Section 7(b)(2) of the 1980 Pacific Northwest Electric Power Planning and Conservation Act specifies a similar counterfactual calculation and has been the subject ever since.

A. Yes. I have identified two important problems. One is so unusual that I am tempted to describe it as a contract drafting error. The other constitutes an unusual feature that may eliminate seller's credit support after the onset of commercial operation.

Q. What is "credit support"?

A. Credit support is a common feature in energy contracts where the parties take precautions to ensure that the counterparty will be financially able to perform under the contract. In this case the provision is quite moderate: $10/kW of nameplate capacity during the period before commercial operation. As noted above, the contract is somewhat unclear about the nameplate capacity, since Exhibit A only specifies that the contract is less than 30 megawatts.

Q. How much money is involved?

A. There are 1,000 kilowatts in a megawatt, so the seller's per-commercial operation credit support is $10 x 1,000 x 30 megawatts at most, or $300,000. This is small compared to the estimated $205,403,512 million in projected program costs from Appendix X – approximately one day of the projected construction costs.

Q. Is this sufficient to protect National Grid and ratepayers against possible contingencies?

A, No. However, all contract negotiations are complex and the small degree of credit support may have been conceded by National Grid in return for some concession by Deepwater Wind.

Unfortunately, it appears that there either was a drafting error or a miscomprehension on behalf of National Grid in the next section that might well reduce seller's credit support to zero after commercial operation.

Q. What is the problem?

A. A close reading of the credit support language after commercial operation reveals a possible drafting error:

> (b) On or before the tenth (10th) day following the date on which Commercial Operation occurs, Seller shall provide Buyer with Credit Support to secure Seller's obligations under this Agreement ("Operating Period Security"). The Operating Period Security shall be $30 per installed kW of Capacity and shall be subject to replenishment from time to time, within five (5) Business Days after Buyer draws on the Operating Period Security, up to the amount required by this Section 6.1(b), but in any event, not to exceed $1,800,000 on an aggregate, cumulative basis, including all prior Credit Support provided as Operating Period Security. Buyer shall return any undrawn amount of the Operating Period

> Security to Seller within thirty (30) days after the expiration of the Services Term, or termination of the Agreement, but only after such Operating Period Security has been used to satisfy any outstanding obligations of Seller in existence at the time of such expiration or termination.

At first reading it appears that seller's credit support is intended to increase from $10/kW to $30/kW after commercial operation. The use of the term "Capacity" poses a problem, however, since "Capacity" is a defined term in this contract:

> "Capacity" shall mean on or as of any date of determination, the Facility's capability to generate a specific amount of electrical energy at any point in time, including without limitation, all capacity from the Facility as determined by ISO-NE's Seasonal Claimed Capability rating (or successor or replacement rating used to measure capability) as defined in the ISO-NE Rules that is obligated to deliver and receive payments in the Forward Capacity Market (or its successor market) as set forth in the ISO-NE Rules, including without limitation as both a "New" and an "Existing" Capacity Resource as those terms are used in the ISO-NE Rules.[35]

This sets the amount of credit support upon a determination by the New England Independent System Operator, which sets capacity for wind based on its Market Rule 1 which describes an extensive qualification process that is likely to change over time.

Q. What is the capacity associated with a wind resource?

A. There is extensive debate on this point throughout the U.S. and Canada. Traditionalists argue that wind resources often have zero capacity value since the wind might not be blowing at system peak. New England currently has a less rigorous standard that provides some capacity value depending on site-specific data.[36] It is not necessary for this debate to be recapitulated in this proceeding. It is important, however, to realize that the credit support will change by season and may well be zero if the New England ISO standards change or Deepwater Wind fails to meet the certification standards set out in the ISO New England tariffs.

Q. Can you describe the ISO-NE's Seasonal Claimed Capabilities protocol?

A. Yes. The Seasonal Claimed Capabilities for wind assets are determined by the process described in the Intermittent Power Resources section of the NE ISO's Market Rule 1 III.13.1.2.2.2, subsections 1 and 2.

[35] Amended PPA, page 2.

[36] See III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

> For Intermittent Power Resources, or Intermittent Settlement Only Resources, the first Forward Capacity Auction Qualified Capacity is determined by the median of the net output during the Summer or Winter Intermittent Reliability Hours. For all other Forward Capacity Auctions, the median of the first five years sets the quantity. Summer is defined as lasting from June through September, and winter is defined as October through May. Summer Intermittent Reliability hours are 2 pm through 6pm, while winter hours are 6pm through 7 pm. For Resources that have not yet achieved Commercial Operation the Qualified Capacity is equal to the capacity cleared from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.
>
> (a) With regard to the first Forward Capacity Auction, for each of the previous four summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.1(c). With regard to any Forward Capacity Auction after the initial Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.1(c).
>
> (c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and, after June 1, 2010, hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import constrained Capacity Zone, all Shortage Events in that Capacity Zone.[37]

Q. Did Mr. Nickerson conduct a calculation of Seasonal Claimed Capacity?

A. Yes. His calculations are:

> While the expected overall annual capacity factor is 40% on an energy basis, for FCM purposes the project has a 36.1% capacity factor in the summer (June through September under ISO-NE rules) and a 50.0% winter value. On a seasonally weighted basis the capacity factor is 45.3% and multiplied by 28.8 MW, the project's FCM value is about 13 MW.[38]

[37] Market Rule 1 III.13.1.2.2.2.1 Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

[38] Docket No. 4111, Direct Testimony of David Nickerson, page 23.

Q. Can you describe the results of defining credit support in terms of the ISO-NE's Seasonal Claimed Capability protocol?

A. Yes. Using Mr. Nickerson's estimates, credit support would be equal to the nameplate capacity in kilowatts multiplied by the seasonal capacity factor, multiplied by $30. Winter credit support would be 28.8 MW x 1,000 x 50.0% x $30 = $432,000, and summer credit support would be 28.8 MW x 1,000 x 36.1% x $30 = $311,904.

Q. Is this a commercially reasonable provision for credit support?

A. No. It is not reasonable to calculate credit support based on a standard designed to qualify the project at a later date for inclusion in the ISO-NE capacity markets.

Q. Is this the only error in the contract?

A. No. A considerably more serious error occurs in Section 9.3. This section summarizes remedies – specifically termination payments if the contract fails. Section 9.3(b)(ii) states:

> (ii) Termination by Seller On or After Construction Financing. If Seller terminates this Agreement because of an Event of Default by Buyer occurring on or after the close of construction Financing for the Facility, the Termination Payment due to Seller shall be equal to the amount, if positive, calculated according to the following formula:
>
> $$\sum_{N}[(CV - MV) + P]$$
>
> where:
>
> "Σ" is the summation over the Services Term.
> N
>
> "CV" is the contract value of the Products for the remainder of the Services Term calculated with reference to the applicable Price and the Supply Forecast.
>
> "MV" is the market value of the Products for the remaining Services Term as determined with reference to the applicable Resale Price and the Supply Forecast.
>
> "P" is the amount of any applicable penalties and administrative costs incurred by Seller in selling the Products not accepted and paid for by Buyer as a result of the termination of this Agreement.

> All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Seller shall provide Buyer with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(ii), which calculation shall be binding upon Buyer, absent manifest error.[39]

Q. Can you describe the problem?

A. Yes. Both this section and Section 9.3(b)(v) omit calculating the present value of the future stream of payments. Since this is a twenty-year contract, the termination payment as calculated here will differ from the actual economic interests of the parties by a considerable degree. Citing the present value in termination provisions is the standard since the termination payment is intended to make the injured party whole, not confer a windfall profit or loss.

Q. Why does this matter?

A. If one of the parties has an incentive to make the contract fail, it will add to the probability that the contract will fail. This omission creates such an incentive.

Q. Why do you think that this is an omission?

A. The contemporaneous contract between Cape Wind and National Grid includes the language specifying present value in the termination payment calculation:

> "RV" is the replacement value of Buyer's Percentage Entitlement of the Products for the remainder of the Services Term, calculated with reference to the applicable Replacement Price and the Supply Forecast, using a discount factor of eight percent (8.0%).
>
> "CV" is the contract value of Buyer's Percentage Entitlement of the Products for the remainder of the Services Term calculated with reference to the applicable Price and the Supply Forecast, using a discount factor of eight percent (8.0%) (the "Contract Value").
>
> "P" is the amount of any applicable penalties and costs incurred by Buyer in replacing the Products not Delivered to Buyer as a result of the termination of this Agreement.[40]

[39] Amended PPA, page 31.

[40] POWER PURCHASE AGREEMENT BETWEEN MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY, D/B/A NATIONAL GRID, AS BUYER AND CAPE WIND ASSOCIATES, LLC, AS SELLER As of May 7, 2010, page 44.

Q. Are there other problematic issues in the contract?

A. Yes. As I mentioned above, the size of the project is not specified in the contract. Exhibit A sets the maximum nameplate capacity at 30 megawatts and limits the project to eight turbines. Appendix X reduces the bundled price as the project's cost falls below $205,403,512 without specifying the amount of equipment being purchased. Exhibit Y specifies – with a small mathematical error – the production target as a function of the as yet undetermined nameplate capacity. This gives Deepwater Wind an interesting incentive to increase the capacity of the project to 30 megawatts even if the purchaser might have gained a price reduction under Appendix Y at 28.8 megawatts.

Q. Is this a fruitful area for future litigation?

A. Conceivably. Nameplate capacity is just that – the capacity on the nameplate. It is not a defined term in the contract, nor is nameplate capacity always identical with actual capacity. Moreover, although Deepwater Wind's calculations have envisaged eight turbines at 3.6 megawatts, other configurations are certainly possible. Alpha Ventus, for example, is using the recently introduced 5 megawatt turbines.

Q. Can you describe the small error in Exhibit Y?

A. Yes. Exhibit Y omits to calculate the correct number of hours in leap years. Section 1.(a) sets the number of hours to 8,760 for every contract year regardless of the actual number. This is not a major issue, but it does go to the question of the level of review exercised in the preparation of the contract.

Q. Can you easily interpret the language in Exhibit Y?

A. No. While the language may not be in error, it lacks clarity. I presume that it is intended to match the interpretation but forward by Mr. Nickerson in Docket 4111:

> The second reduction is called the Outperformance Adjustment Credit which is effectively a 50% discount to the Bundled Price that applies to energy the project generated above an assumed 40% capacity factor, on a cumulative basis. Using an installed capacity of 28.8 MW, the project in a typical year would generate 100,925 MWh at a 40% capacity factor (28.8 MW x 8,760 hrs x .40). This becomes an annual target output and to the extent over the term of the contract the actual cumulative generation exceeds the amount of the cumulative target, a production surplus is calculated. Half of this surplus then

becomes a credit at the then current Bundled Price in $/MWh, as adjusted for the FCM payments.[41]

Q. Would you change this?

A. Yes, or alternatively, directly include Mr. Nickerson's interpretation in the example.

Q. How "commercially reasonable" is this contract?

A. It is not a commercially reasonable document. As noted above there are possible errors, important sections are unclear and may lead to controversy, and it gives an overall sense of needing a thorough review before execution.

Q. Does this complete your testimony?

A. Yes.

[41] RIDPUC Docket No. 4111, Direct Testimony of Nickerson, page 22.

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth min (m)	Depth max (m)	In-Service Date	Country	Feed-in Tariff Minimum ($/MWh)	Feed-in Tariff Maximum ($/MWh)	Addition To Market	Estimated Cost of Production
Aiolos	985	197	115	37	41	2013	Germany	$ 45.00	$ 150.00	No	
Albatros	400	80	75	39	41	2013	Germany	$ 45.00	$ 150.00	No	
Alpha Ventus	60	12	56	28	30	2010	Germany	$ 45.00	$ 150.00	No	
Amrumbank West	400	80	55	20	25	2015	Germany	$ 45.00	$ 150.00	No	
Aquamarin	400	80	83	35	39	2015	Germany	$ 45.00	$ 150.00	No	
Arcadis Ost 1	350	70	17	44	46	2014	Germany	$ 45.00	$ 150.00	No	
Arcadis Ost 2	75	25	40.9	28	37		Germany	$ 45.00	$ 150.00	No	
AreaC I	400	80	66	37	37		Germany	$ 45.00	$ 150.00	No	
AreaC II	400	80	66	34	37		Germany	$ 45.00	$ 150.00	No	
AreaC III	400	80	66	36	37		Germany	$ 45.00	$ 150.00	No	
Arklow Bank	25	7	10	1	35	2004	Ireland	$ 140.00	$ 140.00	No	
Arkona Becken Südost	400		35	21	27	2014	Germany	$ 45.00	$ 150.00	No	
ArkonaSee Süd	Undecided	80	26.4	41	41		Germany	$ 45.00	$ 150.00	No	
ArkonaSee West	Undecided	Undecided	25.7	41	42		Germany	$ 45.00	$ 150.00	No	
Austerngrund	400	80	128.5	41	41	2014	Germany	$ 45.00	$ 150.00	No	
Avedore/Hvidovre	7	2	1.4	2	2	2009	Denmark	$ 70.00	$ 84.00	Yes	
Baltic 1	48	21	16	16	19	2010	Germany	$ 45.00	$ 150.00	No	
BalticEagle	480	80	30	40	44		Germany	$ 45.00	$ 150.00	No	
Baltic Power East	400	80	33.4	43	47		Germany	$ 45.00	$ 150.00	No	
Baltic Power West	400	80	31.8	41	42		Germany	$ 45.00	$ 150.00	No	
Bard Offshore 1	400	80	101	39	41	2010	Germany	$ 45.00	$ 150.00	No	
Barrow	90	30	7.5	12	16	2006	United Kingdom	$ -	$ -		
Beatrice (Moray Firth)	920	184	15	35	50	2017	United Kingdom	$ -	$ -		
Beltsee	125	25	9	23	27	2013	Germany	$ 45.00	$ 150.00	No	
Belwind Phase I	165	55	41	15	30	2011	Belgium	$ 70.00	$ 95.00	Yes	
Belwind Phase II	165	55	42	16	31	2012	Belgium	$ 70.00	$ 95.00	Yes	
Bernstein	400	80	90	41	41	2016	Germany	$ 45.00	$ 150.00	No	
Beta Baltic	150	50	15.8	21	22	2013	Germany	$ 45.00	$ 150.00	No	
Bight Power I	400	80	74	35	39		Germany	$ 45.00	$ 150.00	No	
Bight Power II	400	80	74	37	39		Germany	$ 45.00	$ 150.00	No	
Tricase	92	24	20	118	118	2011	Italy				
Blyth	4	2	1	5	5	2000	United Kingdom	$ -	$ -		
Bockstigen	3	5	4	5	6	1998	Sweden				
Bohai Bay	1.5	1	70	32	32	2007	China				
OWP Riffgat	108	30	29	18	23	2011	Germany	$ 45.00	$ 150.00	No	
Borkum Riffgrund I	277	77	54	23	29	2015	Germany	$ 45.00	$ 150.00	No	
Borkum Riffgrund II	480	96	57	25	29	2013	Germany	$ 45.00	$ 150.00	No	
Borkum Riffgrund West	400	80	67	29	33	2015	Germany	$ 45.00	$ 150.00	No	
Borkum Riffgrund West II	400	80	67	29	31		Germany	$ 45.00	$ 150.00	No	
Borkum West II	200	40	65.6	31	33	2012	Germany	$ 45.00	$ 150.00	No	
Breitling	3	1	0.3	0.5	0.5	2006	Germany	$ 45.00	$ 150.00	No	
Brindisi	0.8	1	21.3	113		2008	Italy				
Burbo Bank	90	25	6.4	0	6	2007	United Kingdom	$ -	$ -		$ 104.09
Offshore-Burgerpark Butendiek	288	80	54	17	20	2012	Germany	$ 45.00	$ 150.00	No	
Choshi	2	1				2012	Japan				
Citrin	400	80	111	41	41	2017	Germany	$ 45.00	$ 150.00	No	
Dan Tysk	400	80	70	21	29	2013	Germany	$ 45.00	$ 150.00	No	
Dan Tysk DK	1200	240	48	21	28		Denmark	$ 70.00	$ 84.00	Yes	

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth min (m)	Depth max (m)	In-Service Date	Country	Feed-in Tariff Minimum ($/MWh)	Feed-in Tariff Maximum ($/MWh)	Addition To Market	Estimated Cost of Production
Deutsche Bucht	400	80	98	38	40	2013	Germany	$ 45.00	$ 150.00	No	
Diamant	400	80	111	41	45	2014	Germany	$ 45.00	$ 150.00	No	
Emden	5	1	0	0	2	2004	Germany	$ 45.00	$ 150.00	No	
Egmond aan Zee	108	36	10	15	18	2008	Netherlands				
Euklas	Undecided	160	143	45	45	2014	Germany	$ 45.00	$ 150.00	No	
Frederikshavn	11	4	3.2	1	4	2003	Denmark	$ 70.00	$ 84.00	Yes	
Gaia I	400	80	135	44	44	2024	Germany	$ 45.00	$ 150.00	No	
Gaia II	400	80	135.5	39	40	2023	Germany	$ 45.00	$ 150.00	No	
Gaia III	400	80	138.5	40	42	2022	Germany	$ 45.00	$ 150.00	No	
Gaia IV	400	80	132.9	39	40	2021	Germany	$ 45.00	$ 150.00	No	
Gaia V	400	80	131.2	40	40	2020	Germany	$ 45.00	$ 150.00	No	
Geofree	25	5	19	20	21	2012	Germany	$ 45.00	$ 150.00	No	
Global Tech I	400	80	115	38	41	2013	Germany	$ 45.00	$ 150.00	No	
Gode Wind I	400	80	40	28	34	2011	Germany	$ 45.00	$ 150.00	No	
Gode Wind II	400	80	40	31	34	2012	Germany	$ 45.00	$ 150.00	No	
Greater Gabbard	504	140	36	4	37	2012	United Kingdom	$ -	$ -		
Gunfleet Sands	173	48	7	0.5	13	2010	United Kingdom	$ -	$ -		
He Dreiht	400	80	97	37	40	2015	Germany	$ 45.00	$ 150.00	No	
He Dreiht II	140	28	46	37	39	2015	Germany	$ 45.00	$ 150.00	No	
Hochsee Testfeld Helgoland	95	19	47.6	22	24		Germany	$ 45.00	$ 150.00	No	
Hochsee Windpark Nordsee	400	80	100	39	40	2011	Germany	$ 45.00	$ 150.00	No	
Hokkaido	400	80	100	39	40	2011	Germany	$ 45.00	$ 150.00	No	
Hooksiel	5	1	0.4	5	5	2008	Germany	$ 45.00	$ 150.00	No	
Horizont I	325	65	125	39	41	2015	Germany	$ 45.00	$ 150.00	No	
Horizont II	380	65	121	41	42		Germany	$ 45.00	$ 150.00	No	
Horizont III	355	71	131	40	41		Germany	$ 45.00	$ 150.00	No	
Horns Rev	160	80	17.9	6	11	2002	Denmark	$ 70.00	$ 84.00	Yes	$ 87.21
Horns Rev 2	209	91	31.7	9	17	2009	Denmark	$ 70.00	$ 84.00	Yes	
Horns Rev A-E	1200		19.5-46.8			2025	Denmark	$ 70.00	$ 84.00	Yes	
Hywind/Karmoy (Floating Pilot)	2	1	10	220	220	2009	Norway				
Inner Dowsing	97	27	5	6	8	2009	United Kingdom	$ -	$ -		
Innogy Nordsee 1	960	180	47.3	26	34	2015	Germany	$ 45.00	$ 150.00	No	
Irene Vorrink	17	28	0	2	3	1996	Netherlands				
Kaikas	415	83	89	41	41	2013	Germany	$ 45.00	$ 150.00	No	
Kemi Ajos	30	10	2.6	1	7	2008	Finland	$ -	$ -		
Kemi Ajos Phase III	200	64				2011	Finland	$ -	$ -		
Kentish Flats	90	30	8.5	3	5	2005	United Kingdom	$ -	$ -		$ 108.31
Kopenhagen	7.2	2				2015	Denmark	$ 70.00	$ 84.00	Yes	
Kriegers Flak II	640	128	32.7	16	39	2015	Sweden				
Kriegers Flak III	455	91				2016	Denmark	$ 70.00	$ 84.00	Yes	
Kriegers Flak R	200		20.7			2025	Denmark	$ 70.00	$ 84.00	Yes	
Kriegers Flak S	200		33.4			2025	Denmark	$ 70.00	$ 84.00	Yes	
Kriegers Flak T	200		28.5			2025	Denmark	$ 70.00	$ 84.00	Yes	
Kriegers Flak U	200		28.5			2025	Denmark	$ 70.00	$ 84.00	Yes	
Lely	2	4	0.8	3	4	1994	Netherlands				
Liaodong Bay	1.5	1					China				
Lillgrunden	110	48	11.3	4	13	2007	Sweden				$ 109.71
London Array	630	175	20	0	23	2012	United Kingdom	$ -	$ -		

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth min (m)	Depth max (m)	In-Service Date	Country	Feed-in Tariff Minimum ($/MWh)	Feed-in Tariff Maximum ($/MWh)	Addition To Market	Estimated Cost of Production
Lynn	97	27	5	7	11	2009	United Kingdom	$ -	$ -		
Mecklenburg- Vorpommen	1.5	3				1993	Germany	$ 45.00	$ 150.00	No	
Meerwind Ost	200	40	53	22	26	2013	Germany	$ 45.00	$ 150.00	No	
Meerwind Süd	200	40	23	25	26	2013	Germany	$ 45.00	$ 150.00	No	
Meerwind Südwest		161	72	24	33		Germany	$ 45.00	$ 150.00	No	
MEG Offshore I	400	80	60.6	27	33	2000	Germany	$ 45.00	$ 150.00	No	
Middelgrunden	40	20	4.7	3	6	2000	Denmark	$ 70.00	$ 84.00	Yes	$ 92.84
Moray Firth	10	2	25	43	43	2006	United Kingdom	$ -	$ -		
Noordzeewind	108	36	14	30	30	2006	Netherlands				
OWP Nordergrunde	90	18	16	3	11	2011	Germany	$ 45.00	$ 150.00	No	
Nördlicher Grund	320	64	84	27	38	2011	Germany	$ 45.00	$ 150.00	No	
Nordpassage	400	80	75	23	33		Germany	$ 45.00	$ 150.00	No	
Nordsee Ost	295	48	57	22	25	2013	Germany	$ 45.00	$ 150.00	No	
North Hoyle	60	30	7.2	5	12	2003	United Kingdom	$ -	$ -		$ 108.31
Notos	250	50	89	41	41		Germany	$ 45.00	$ 150.00	No	
nSWP 4	486	81	205	43	43		Germany	$ 45.00	$ 150.00	No	
nSWP 5	510	85	158	43	43		Germany	$ 45.00	$ 150.00	No	
nSWP 6	504	84	190	43	43		Germany	$ 45.00	$ 150.00	No	
nSWP 7	570	95	158	43	43		Germany	$ 45.00	$ 150.00	No	
Nysted	166	72	10.8	6	9	2003	Denmark	$ 70.00	$ 84.00	Yes	$ 84.40
OWP Delta Nordsee II	160	32	51.1	29	33	2013	Germany	$ 45.00	$ 150.00	No	
OWP Delta Nordsee I	240	48	50	26	34	2012	Germany	$ 45.00	$ 150.00	No	
Ormonde	150	30	9.5	17	21	2011	United Kingdom	$ -	$ -		
OWP West	400	80	67	29	31		Germany	$ 45.00	$ 150.00	No	
Puerto de Bilbao	250						Spain	$ 73.00	$ 73.00		
Princess Amalia (Q7-WP)	120	60	23	19	24	2008	Netherlands				
Rhyl Flats	90	25	8	4	11	2009	United Kingdom	$ -	$ -		
Robin Rigg	180	60	11	0	12	2010	United Kingdom	$ -	$ -		$ 130.81
Rodsand II	207	90	68	93	115	2010	Denmark	$ 70.00	$ 84.00	Yes	
Ronland	9	4	0.1	0	2	2002	Denmark	$ 70.00	$ 84.00	Yes	
Rostock	2.5	1	1	2	2	2006	Germany	$ 45.00	$ 150.00	No	
Samsø	23	10	4	10	13	2003	Denmark	$ 70.00	$ 84.00	Yes	$ 87.21
Sandbank 24	288	96	83	25	37	2012	Germany	$ 45.00	$ 150.00	No	
Scroby Sands	60	30	2.3	0	8	2004	United Kingdom	$ -	$ -		$ 108.31
Sea storm I	400	80	110	42	42	2015	Germany	$ 45.00	$ 150.00	No	
Sea storm II	190	38	110	42	42	2015	Germany	$ 45.00	$ 150.00	No	
Sea Wind I	400	80	90	39	40	2013	Germany	$ 45.00	$ 150.00	No	
Sea Wind II	300	60	90	40	41	2014	Germany	$ 45.00	$ 150.00	No	
Sea Wind III	400	80	110	42	42	2017	Germany	$ 45.00	$ 150.00	No	
Sea Wind IV		60	104	41	42	2019	Germany	$ 45.00	$ 150.00	No	
Setana	1	2	0.7	10	10	2004	Japan				
Shanghai East China Sea Bridge	102	34	8 to 14	8	10	2010	China				
Sheringham Shoal	317	88	23	14	23	2011	United Kingdom	$ -	$ -		
Skua	400	80	85	38	39	2009	Germany	$ 45.00	$ 150.00	No	
Sprogo	21	7	10.6	6	16	2009	Denmark	$ 70.00	$ 84.00	Yes	
Thanet	300	100	12	14	23	2010	United Kingdom	$ -	$ -		
Thornton Bank I	30	6	27	13	19	2009	Belgium	$ 70.00	$ 95.00	Yes	
Thornton Bank II	126	24	27	6	20	2010	Belgium	$ 70.00	$ 95.00	Yes	
Thornton Bank III	144	24	26	10	20	2012	Belgium	$ 70.00	$ 95.00	Yes	

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth min (m)	Depth max (m)	In-Service Date	Country	Feed-in Tariff Minimum ($/MWh)	Feed-in Tariff Maximum ($/MWh)	Addition To Market	Estimated Cost of Production
Tuno Knob	5	10	5.5	4	7	1995	Denmark	$ 70.00	$ 84.00	Yes	
Utgrunden I	11	7	4.2	6	15	2000	Sweden				
Utgrunden II	90	24	5.9	4	20	2013	Sweden				
Uthland	400	80	70	21	29	2015	Germany	$ 45.00	$ 150.00	No	
Veja Mate	400	80	114.1	39	41	2012	Germany	$ 45.00	$ 150.00	No	
Ventotec Ost 2 (Wikinger)	400	80	35	36	40	2014	Germany	$ 45.00	$ 150.00	No	
Vindeby	5	11	1.8	2	4	1991	Denmark	$ 70.00	$ 84.00	Yes	
Walney I	184	51	14	19	23	2011	United Kingdom	$ -	$ -		
Walney II	184	51	14	24	30	2012	United Kingdom	$ -	$ -		
Walney Extension	750		29	21	50	2016	United Kingdom	$ -	$ -		
Weiße Bank	320	80	105	29	33		Germany	$ 45.00	$ 150.00	No	
Witte Bank		171	120	45	45		Germany	$ 45.00	$ 150.00	No	
Yttre Stengrund	10	5	2	6	8	2001	Sweden				

Robert McCullough – *Curriculum Vitae*

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Fax: 503-777-0196

Professional Experience

1985-present	Managing Partner, McCullough Research: provide strategic planning assistance, litigation support, and planning for a variety of customers in energy, regulation, and primary metals
1996-present	Adjunct Professor, Economics, Portland State University
1990-1991	Director of Special Projects and Assistant to the Chairman of the Board, Portland General Corporation: conducted special assignments for the Chairman in the areas of power supply, regulation, and strategic planning
1988-1990	Vice President in Portland General Corporation's bulk power marketing utility subsidiary, Portland General Exchange: primary negotiator on the purchase of 550 MW transmission and capacity package from Bonneville Power Administration; primary negotiator of PGX/M, PGC's joint venture to establish a bulk power marketing entity in the Midwest; negotiated power contracts for both supply and sales; coordinated research function
1987-1988	Manager of Financial Analysis, Portland General Corporation: responsible for M&A analysis, restructuring planning, and research support for the financial function; reported directly to the CEO on the establishment of Portland General Exchange; team member of PGC's acquisitions task force; coordinated PGC's strategic planning process; transferred to the officer's merit program as a critical corporate manager

1981-1987	Manager of Regulatory Finance, Portland General Electric: responsible for a broad range of regulatory and planning areas, including preparation and presentation of PGE's financial testimony in rate cases in 1980, 1981, 1982, 1983, 1985, and 1987 before the Oregon Public Utilities Commission; responsible for preparation and presentation of PGE's wholesale rate case with Bonneville Power Administration in 1980, 1981, 1982, 1983, 1985, and 1987; coordinated activities at BPA and FERC on wholesale matters for the InterCompany Pool (the association of investor-owned utilities in the Pacific Northwest) since 1983; created BPA's innovative aluminum tariffs (adopted by BPA in 1986); led PGC activities, reporting directly to the CEO and CFO on a number of special activities, including litigation and negotiations concerning WPPSS, the Northwest Regional Planning Council, various electoral initiatives, and the development of specific tariffs for major industrial customers; member of the Washington Governor's Task Force on the Vancouver Smelter (1987) and the Washington Governor's Task Force on WPPSS Refinancing (1985); member of the Oregon Governor's Work Group On Extra-Regional Sales (1983); member of the Advisory Committee to the Northwest Regional Planning Council (1981)
1979-1980	Economist, Rates and Revenues Department, Portland General Electric: responsible for financial and economic testimony in the 1980 general case; coordinated testimony in support of the creation of the DRPA (Domestic and Rural Power Authority) and was a witness in opposition to the creation of the Columbia Public Utility District in state court; member of the Scientific and Advisory Committee to the Northwest Regional Power Planning Council
1976-1979	Graduate student, Cornell University: worked as an economist for Institutional Research directly for the Vice-President of Planning; co-investigator on a major grant from the Department of Labor's Bureau of International Labor Affairs; performed statistical and demographic analysis for the New York State Consumer Protection Agency
1973-1976	Research Assistant, Economics Department, Portland State University: summer work for the U.S. Bureau of Land Management and the Institute on Aging

1974	Economist, Legislative Research: researched bills before the legislature on issues from land use to economic development
1973	Researcher, Willamette Management Associates: responsible for economic research and writing in various financial periodicals; supported corporate valuation analysis

Economic Consulting

2010	Analysis for Eastern Environmental Law Center of 25 closed cycle plants in New York State
2010	Advisor on BPA transmission line right of way issues
2009-present	Advisor to Gamesa USA on a marketing plan to promote a wind farm in the Pacific Northwest
2009-2010	Expert witness in City of Alexandria vs. Cleco
2008-2009	Consultant to AARP Connecticut and Texas chapters on the need for a state power authority (Connecticut) and balancing energy services (Texas)
2008-present	Advisor to the American Public Power Association on administered markets
2008-present	Expert witness in Snohomish PUD No. 1/Morgan Stanley litigation
2008	Expert witness on trading and derivative issues in Barrick Gold litigation
2008-present	Advisor to Jackson family in Pelton/Round Butte dispute
2006-present	Advisor to the Illinois Attorney General on electric restructuring issues
2006-present	Expert witness for Lloyd's of London in SECLP insurance litigation
2006-2007	Advisor to the City of Portland in the investigation of Portland General Electric
2005-2006	Expert witness for Antara Resources in Enron litigation

2005-2006	Advisor to Utility Choice Electric
2005-2007	Expert witness for Federated Rural Electric Insurance Company and TIG Insurance in Cowlitz insurance litigation
2005-2007	Advisor to Gray's Harbor PUD on market manipulation
2005-2007	Advisor to the Montana Attorney General on market manipulation
2004-2005	Expert witness for Factory Mutual in Northwest Aluminum litigation
2004	Advisor to the Oregon Department of Justice on market manipulation
2003-2006	Expert witness for Texas Commercial Energy
2003-2004	Advisor to The Energy Authority
2002-2005	Advisor to the U.S. Department of Justice on market manipulation issues
2002-2004	Expert witness for Alcan in Powerex arbitration
2002-2003	Expert witness for Overton Power in IdaCorp Energy litigation
2002-2003	Expert witness for Stanislaus Food Products
2002	Advisor to VHA Pennsylvania on power purchasing
2002	Expert witness for Sierra Pacific in Enron litigation
2002-2004	Advisor to U.S. Department of Justice
2002-2007	Expert witness for Snohomish PUD in Enron litigation
2001-2005	Advisor to Nordstrom
2001-2005	Advisor to Steelscape Steel on power issues in Washington and California
2001-2008	Advisor to VHA Southwest on power purchasing

2001-present	Expert witness for City of Seattle, Seattle City Light and City of Tacoma in FERC's EL01-10 refund proceeding
2001	Advisor to California Steel on power purchasing
2001	Advisor to the California Attorney General on market manipulations in the Western Systems Coordinating Council power markets
2000-present	Expert witness for Wah Chang in PacifiCorp litigation
2000-2001	Expert witness for Southern California Edison in Bonneville Power Administration litigation
2000-2001	Advisor to Blue Heron Paper on West Coast price spikes
2000	Expert witness for Georgia Pacific and Bellingham Cold Storage in the Washington Utilities and Transportation Commission's proceeding on power costs
1999	Expert report for the Center Helios on Freedom of Information in Québec
1999-2002	Advisor to Bayou Steel on alternative energy resources
1999-2000	Expert witness for the Large Customer Group in PacifiCorp's general rate case
1999-2000	Expert witness for Tacoma Utilities in WAPA litigation
1999-2000	Advisor for Nucor Steel and Geneva Steel on PacifiCorp's power costs
1999-2000	Advisor to Abitibi-Consolidated on energy supply issues
1999	Advisor to GTE regarding Internet access in competitive telecommunication markets
1999	Advisor to Logansport Municipal Utilities
1998-2001	Advisor to Edmonton Power on utility plant divestiture in Alberta
1998-2001	Energy advisor for Boise Cascade

1998-2000	Advisor to California Steel on power purchasing
1998-2000	Advisor to Nucor Steel on power purchasing and transmission negotiations
1998-2000	Advisor to Cominco Metals on the sale of hydroelectric dams in British Columbia
1998-2000	Advisor to the Betsiamites on the purchase of hydroelectric dams in Québec
1998-1999	Advisor to the Illinois Chamber of Commerce concerning the affiliate electric and gas program
1998	Intervention in Québec's first regulatory proceeding on behalf of the Grand Council of the Cree
1998	Market forecasts for Montana Power's restructuring proceeding
1997-1999	Advisor to the Columbia River Intertribal Fish Commission on Columbia fish and wildlife issues
1997-1998	Advisor to Port of Morrow regarding power marketing with respect to existing gas turbine plant
1997-1998	Expert witness for Tenaska in BPA litigation
1997	Advisor to Kansai Electric on restructuring in the electric power industry (with emphasis on the California markets)
1997-2004	Expert witness for Alcan in BC Hydro litigation
1996-1997	Bulk power purchasing for the Association of Bay Area Cities
1996-1997	Advisor to Texas Utilities on industrial issues
1996-1997	Expert witness for March Point Cogeneration in Puget Sound Power and Light litigation
1996	Advisor to Longview Fibre on contract issues
1995-present	Bulk power supplier for several Pacific Northwest industrials

1995-1997	Advisor to Tacoma Utilities on contract issues
1995-1999	Advisor to Seattle City Light on industrial contract issues
1995-1996	Expert witness for Tacoma Utilities in WAPA litigation
1994-1995	Advisor to Idaho Power on Southwest Intertie Project marketing
1993-2001	Northwest representative for Edmonton Power
1993-1997	Expert witness for MagCorp in PacifiCorp litigation
1992-1995	Advisor to Citizens Energy Corporation
1992-1994	Negotiator on proposed Bonneville Power Administration aluminum contracts
1992	Bulk power marketing advisor to Public Service of Indiana
1997-2003	Advisor to the Manitoba Cree on energy issues in Manitoba, Minnesota and Québec; Advisor to the Grand Council of the Cree on hydroelectric development
1991-2000	Strategic advisor to the Chairman of the Board, Portland General Corporation
1991-1993	Chairman of the Investor Owned Utilities' (ICP) committee on BPA financial reform
1991-1992	Financial advisor on the Trojan owners' negotiation team
1991	Advisor to Shasta Dam PUD on the California Oregon Transmission Project and related issues
1990-1991	Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN
1988	Facilitated the settlement of Commonwealth Edison's 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included

	financial advice to the Commission and negotiations with Commonwealth and interveners
1987-1988	Created the variable aluminum tariff for Big Rivers Electric Corporation: responsibilities included testimony before the Kentucky Public Service Commission and negotiations with BREC's customers (the innovative variable tariff was adopted by the Commission in August 1987); supported negotiations with the REA in support of BREC's bailout debt restructuring
1981-1989	Consulting projects including: financial advice for the Oregon AFL-CIO; statistical analysis of equal opportunity for Oregon Bank; cost of capital for the James River dioxin review; and economic analysis of qualifying facilities for Washington Hydro Associates
1980-1986	Taught classes in senior and graduate forecasting, micro-economics, and energy at Portland State University

Education

Unfinished Ph.D.	Economics, Cornell University; Teaching Assistant in micro- and macro-economics
M.A.	Economics, Portland State University, 1975; Research Assistant
B.A.	Economics, Reed College, 1972; undergraduate thesis, "Eurodollar Credit Creation"

Areas of specialization include micro-economics, statistics, and finance

Volunteer Activities

Chairman	Portland State University Economics Department: advisory committee
Member	Portland State College of Arts and Sciences: advisory committee
Board Member:	Eastmoreland Neighborhood Association
Board Member:	Academus Project

Professional Affiliations

American Economic Association; American Financial Association; Econometric Society

Papers and Publications

July 2009	"Fingerprinting the Invisible Hand", *Public Utilities Fortnightly*
February 2008	Co-author, "The High Cost of Restructuring", *Public Utilities Fortnightly*
March 27, 2006	Co-author, "A Decisive Time for LNG", *The Daily Astorian*
February 9, 2006	"Opening the Books", *The Oregonian*
August 2005	"Squeezing Scarcity from Abundance", *Public Utilities Fortnightly*
April 1, 2002	"The California Crisis: One Year Later", *Public Utilities Fortnightly*
March 13, 2002	"A Sudden Squall", *The Seattle Times*
March 1, 2002	"What the ISO Data Says About the Energy Crisis", *Energy User News*
February 1, 2001	"What Oregon Should Know About the ISO", *Public Utilities Fortnightly*
January 1, 2001	"Price Spike Tsunami: How Market Power Soaked California", *Public Utilities Fortnightly*
March 1999	"Winners & Losers in California", *Public Utilities Fortnightly*
July 15, 1998	"Are Customers Necessary?", *Public Utilities Fortnightly*
March 15, 1998	"Can Electricity Markets Work Without Capacity Prices?", *Public Utilities Fortnightly*

February 1998	"Coping With Interruptibility", *Energy Buyer*
January 1998	"Pondering the Power Exchange", *Energy Buyer*
December 1997	"Getting There Is Half the Cost: How Much Is Transmission Service?", *Energy Buyer*
November 1997	"Is Capacity Dead?", *Energy Buyer*
October 1997	"Pacific Northwest: An Overview", *Energy Buyer*
August 1997	"A Primer on Price Volatility", *Energy Buyer*
June 1997	"A Revisionist's History of the Future", *Energy Buyer*
Winter 1996	"What Are We Waiting for?" *Megawatt Markets*
October 21, 1996	"Trading on the Index: Spot Markets and Price Spreads in the Western Interconnection", *Public Utilities Fortnightly*
October 1996	"Knowing When to Save Millions", *Competitive Utility*
January 1996	"Predators and Prey", *Competitive Utility*
November 29, 1995	"Should We Be Waiting for FERC? (Or Congress, or the State Commissions)", *Megawatt Markets*
October 1995	"Estimating the Competitive Dividend", *Competitive Utility*

McCullough Research Reports

March 1, 2010	"Translation" of the September 29, 2008 NY Risk Consultant's Hydraulics Report to Manitoba Hydro CEO Bob Brennan
December 2, 2009	"Review of the ICF Report on Manitoba Hydro Export Sales"
June 5, 2009	"New York State Electricity Plants' Profitability Results"
May 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas"
April 7, 2009	"A Forensic Analysis of Pickens' Peak: Speculation, Fundamentals or Market Structure"

March 30, 2009	"New Yorkers Lost $2.2 Billion Because of NYISO Practices"
March 3, 2009	"The New York Independent System Operator's Market-Clearing Price Auction is Too Expensive for New York"
February 24, 2009	"The Need for a Connecticut Power Authority"
January 7, 2009	"Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study"
August 6, 2008	"Seeking the Causes of the July 3rd Spike in World Oil Prices" (updated September 16, 2008)
April 7, 2008	"Kaye Scholer's Redacted 'Analysis of Possible Complaints Relating to Maryland's SOS Auctions'"
February 1, 2008	"Some Observations on Societe Generale's Risk Controls"
June 26, 2007	"Looking for the 'Voom': A Rebuttal to Dr. Hogan's 'Acting in Time: Regulating Wholesale Electricity Markets'"
September 26, 2006	"Did Amaranth Advisors, LLC Attempt to Corner the March 2007 NYMEX at Henry Hub?"
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio: Energy Strategies for Cities and Other Public Agencies"
April 12, 2005	"When Oil Prices Rise, Using More Ethanol Helps Save Money at the Gas Pump"
April 12, 2005	"When Farmers Outperform Sheiks: Why Adding Ethanol to the U.S. Fuel Mix Makes Sense in a $50-Plus/Barrel Oil Market"
April 12, 2005	"Enron's Per Se Anti-Trust Activities in New York"
February 15, 2005	"Employment Impacts of Shifting BPA to Market Pricing"
June 28, 2004	"Reading Enron's Scheme Accounting Materials"
June 5, 2004	"ERCOT BES Event"
August 14, 2003	"Fat Boy Report"

May 16, 2003	"CERA Decision Brief"
January 16, 2003	"California Electricity Price Spikes"
November 29, 2002	"C66 and Artificial Congestion Transmission in January 2001"
August 17, 2002	"Three Days of Crisis at the California ISO"
July 9, 2002	"Market Efficiencies"
June 26, 2002	"Senate Fact Sheet"
June 5, 2002	"Congestion Manipulation"
May 5, 2002	"Enron's Workout Plan"
March 31, 2002	"A History of LJM2"
February 2, 2002	"Understanding LJM"
January 22, 2002	"Understanding Whitewing"

Testimony and Comment

April 7, 2009	Testimony before the U.S. Senate Committee on Energy and Natural Resources, "Pickens' Peak"
March 5, 2009	Testimony before the New York Assembly Committee on Corporations, Authorities and Commissions, and the Assembly Committee on Energy, "New York Independent System Operators Market Clearing Price Auction is Too Expensive for New York"
February 24, 2009	Testimony before the Energy and Technology Committee, Connecticut General Assembly, "An Act Establishing a Public Power Authority" on behalf of AARP
September 16, 2008	Testimony before the U.S. Senate Committee on Energy and Natural Resources, "Depending On 19th Century Regulatory Institutions to Handle 21st Century Markets"
January 7, 2008	Supplemental Comment ("The Missing Benchmark in Electricity Deregulation") before the Federal Energy

	Regulatory Commission on behalf of American Public Power Association, Docket Nos. RM07-19-000 and AD07-7-000
August 7-8, 2007	Testimony before the Oregon Public Utility Commission on behalf of Wah Chang, Salem, Oregon, Docket No. UM 1002
February 23 and 26, 2007	Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180
October 2, 2006	Direct Testimony before the Régie de l'énergie, Gouvernement du Québec on behalf of the Grand Council of the Cree
August 22, 2006	Rebuttal Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
June 1, 2006	Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
May 8, 2006	Testimony before the U.S. Senate Democratic Policy Committee, "Regulation and Forward Markets: Lessons from Enron and the Western Market Crisis of 2000-2001"
December 15, 2005	Direct Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
December 14, 2005	Deposition before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, No. 04-5052RBL
December 4, 2005	Expert Report on behalf of Utility Choice Electric in Civil Action No. 4:05-CV-00573
July 27, 2005	Expert Report before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility

	District No. 1 of Cowlitz County, Docket No. CV04-5052RBL
May 6, 2005	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
May 1, 2005	Rebuttal Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
March 24-25, 2005	Deposition by Enron Power Marketing, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
February 14, 2005	Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
January 27, 2005	Supplemental Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180, et al.
April 14, 2004	Deposition by Enron Power Marketing, Inc. and Enron Energy Services before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
April 10, 2004	Rebuttal Testimony on behalf of the Office of City and County Attorneys, San Francisco, California, City and County Attorneys, San Francisco, California v. Turlock Irrigation District, Non-Binding Arbitration
February 24, 2004	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
March 20, 2003	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of the City of Seattle, Washington, Docket No. EL01-10, et al.
March 11-13, 2003	Deposition by IdaCorp Energy L.P. before the District Court of the Fourth Judicial District of the State of Idaho

	on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
March 3, 2003	Expert Report before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
February 27, 2003	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington and the Port of Seattle, Washington, Docket No. EL01-10-005
October 7, 2002	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
October 2002	Expert Report before the Circuit Court of the State of Oregon for the County of Multnomah on behalf of Alcan, Inc., Alcan, Inc. v. Powerex Corp., Case No. 50 198 T161 02
September 27, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8-9, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 28, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of

	Snohomish County, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
May 6, 2002	Rebuttal Testimony before the Public Service Commission of Utah on behalf of Magnesium Corporation of America in the Matter of the Petition of Magnesium Corporation of America to Require PacifiCorp to Purchase Power from MagCorp and to Establish Avoided Cost Rates, Docket No. 02-035-02
April 11, 2002	Testimony before the U.S. Senate Committee on Commerce, Science and Transportation, Washington D.C.
February 13, 2002	Testimony before the U.S. House of Representatives Subcommittee on Energy and Air Quality, Washington D.C.
January 29, 2002	Testimony before the U.S. Senate Committee on Energy and Natural Resources, Washington D.C.
August 30, 2001	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
August 16, 2001	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
June 12, 2001	Rebuttal Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
April 17, 2001	Before the Public Utility Commission of the State of Oregon, Direct Testimony on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
March 17, 2000	Rebuttal Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10

February 1, 2000	Direct Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10
November 8, 1999	Expert Report before the United States Court for the Western District of Washington at Tacoma on behalf of the City of Tacoma, Washington, City of Tacoma, Washington v. Western Area Power Administration in C9605699-RJB
January 25, 1996	Declaration in Opposition to Motion for Partial Summary Judgment before the United States District Court Western District of Washington at Seattle on behalf of March Point Cogeneration Company, March Point Cogeneration Company v. Puget Sound Power and Light Company in C95-1833R

Presentations

October 15, 2009	"The Mysterious New York Market", EPIS, Tucson, Arizona
October 14, 2009	"Do ISO Bidding Processes Result in Just and Reasonable Rates?", legal seminar, American Public Power Association, Savannah, Georgia
June 22, 2009	"Pickens' Peak Redux: Fundamentals, Speculation, or Market Structure", International Association for Energy Economics
June 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas", Presentation at Texas Legislature
May 8, 2009	"Pickens' Peak", Economics Department, Portland State University
April 7, 2009	"Pickens' Peak: Speculators, Fundamentals, or Market Structure", 2009 EIA energy conference, Washington, DC
February 4, 2009	"Why We Need a Connecticut Power Authority", presentation to the Energy and Technology Committee, Connecticut General Assembly
October 28, 2008	"The Impact of a Volatile Economy on Energy Markets", NAESCO annual meeting, Santa Monica, California
April 1, 2008	"Connecticut Energy Policy: Critical Times…Critical Decisions", House Energy and Technology Committee, the Connecticut General Assembly
May 23, 2007	"Past Efforts and Future Prospects for Electricity Industry Restructuring: Why Is Competition So Expensive?", Portland State University
February 26, 2007	"Trust, But Verify", Take Back the Power Conference, National Press Club, Washington, D.C.
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio"
February 12, 2005	"Northwest Job Impacts of BPA Market Rates"

January 5, 2005	"Why Has the Enron Crisis Taken So Long To Solve?", Public Power Council, Portland, Oregon
September 20, 2004	"Project Stanley and the Texas Market", Gulf Coast Energy Association, Austin, Texas
September 9, 2004	"Back to the New Market Basics", EPIS, White Salmon, Washington
June 8, 2004	"Caveat Emptor", ELCON West Coast Meeting, Oakland, California
June 9, 2004	"Enron Discovery in EL03-137/180"
March 31, 2004	"Governance and Performance", Public Power Council, Portland, Oregon
January 23, 2004	"Resource Choice", Law Seminars International, Seattle, Washington
January 17, 2003	"California Energy Price Spikes: The Factual Evidence", Law Seminars International Seattle, Washington
January 16, 2003	"The Purloined Agenda: Pursuing Competition in an Era of Secrecy, Guile, and Incompetence"
September 17, 2002	"Three Crisis Days", California Senate Select Committee, Sacramento, California
June 10, 2002	"Enron Schemes", California Senate Select Committee Sacramento, California
May 2, 2002	"One Hundred Years of Solitude"
March 21, 2002	"Enron's International Ventures", Oregon Bar International Law Committee, Portland, Oregon
March 19, 2002	"Coordinating West Coast Power Markets", GasMart, Reno, Nevada
March 19, 2002	"Sauron's Ring", GasMart, Reno, Nevada
January 25, 2002	"Deconstructing Enron's Collapse: Buying and Selling Electricity on The West Coast", Seattle, Washington

January 18, 2002	"Deconstructing Enron's Collapse", Economics Seminar, Portland State University
November 12, 2001	"Artifice or Reality", EPIS Energy Forecast Symposium, Skamania, Washington
October 24, 2001	"The Case of the Missing Crisis" Kennewick Rotary Club, Kennewick, Washington
August 18, 2001	"Preparing for the Next Decade"
June 26, 2001	"Examining the Outlook on Deregulation"
June 25, 2001	Presentation, Energy Purchasing Institute for International Research (IIR), Dallas, Texas
June 6, 2001	"New Horizons: Solutions for the 21st Century", Federal Energy Management-U.S. Department of Energy, Kansas City, Kansas
May 24, 2001	"Five Years"
May 10, 2001	"A Year in Purgatory", Utah Industrial Customers Symposium-Utah Association of Energy Users, Salt Lake City, Utah
May 1, 2001	"What to Expect in the Western Power Markets this Summer", Western Power Market Seminar, Denver, Colorado
April 23, 2001	"Emerging Markets for Natural Gas", West Coast Gas Conference, Portland, Oregon
April 18, 2001	"Demystifying the Influence of Regulatory Mandates on the Energy Economy" Marcus Evans Seminar, Denver, Colorado
April 4, 2001	"Perfect Storm", Regulatory Accounting Conference, Las Vegas, Nevada
March 21, 2001	"After the Storm 2001", Public Utility Seminar, Reno, Nevada
February 21, 2001	"Future Imperfect", Pacific Northwest Steel Association, Portland, Oregon

February 12, 2001	"Power Prices in 2000 through 2005", Northwest Agricultural Chillers, Bellingham, Washington
February 6, 2001	Presentation, Boise Cascade Management, Boise, Idaho
January 19, 2001	"Wholesale Pricing and Location of New Generation Buying and Selling Power in the Pacific Northwest", Seattle, Washington
October 26, 2000	"Tsunami: Market Prices since May 22nd", International Association of Refrigerated Warehouses, Los Vegas, California
October 11, 2000	"Tsunami: Market Prices since May 22nd", Price Spikes Symposium, Portland, Oregon
August 14, 2000	"Anatomy of a Corrupted Market", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 30, 2000	"Northwest Market Power", Governor Locke of Washington, Seattle, Washington
June 10, 2000	"Northwest Market Power", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 5, 2000	"Northwest Market Power", Georgia Pacific Management
May 10, 2000	"Magnesium Corporation Developments", Utah Public Utilities Commission
May 5, 2000	"Northwest Power Developments", Georgia Pacific Management
January 12, 2000	"Northwest Reliability Issues", Oregon Public Utility Commission
December 10, 1999	"Reducing Bidder 'Creativity'"
June 22, 1999	"How to Buy Power in the Pacific Northwest: A Buyer's Perspective", Megawatt Daily, Generation Week and Financial Times Energy Conference

June 8, 1999	"Winners and Losers in California. An Overview of the Deregulated California Energy Market", Western Power Trading Forum
June 7, 1999	"Market Power under AB-1890"
May 17, 1999	Presentation, ISO Market Oversight Committee Seminar sponsored by the Power Industry Computer Application Group, San Jose, California
May 16, 1999	"Electric Market Risk: Clearing Out the Cobwebs"
March 1, 1999	"Electric Competition, One Year Later: Winners and Losers in California"
January 25, 1999	"Coping With Capacity Prices", Metals Week Aluminum Meeting
January 14, 1999	"Factors Driving the Market: Buying and Selling Electricity in the West", Seattle, Washington
December 16, 1998	"Electric Markets: Western Power Markets" (analysis of responses to recent changes in western power markets), Las Vegas, Nevada
November 5, 1998	"Electric Markets – Challenges and Solutions", Puget Power's industrial customers
October 20, 1998	"Evaluating Electric Supply Risk", Georgia Pacific, Bellingham, Washington
September 15, 1998	"Marketing Priest Rapids and Wanapum", Grant County PUD No. 2
September 14, 1998	"Future Pricing Structure in Competitive Markets"
July 16, 1998	"Proactive Strategies and Electricity Markets", Abitibi Consolidated, Inc.
June 18, 1998	"Visions of Power Markets of the Future", Pacific Northwest Gas/Electric Integration Group
June 26, 1998	"Pricing Strategies" (technical pricing and contract trends), American Management Association

June 13, 1998	"Succeeding In Aggregation", New Mexico Retail Association, Durango, Colorado
May 20, 1998	"Managing Electricity Price Risk: Practical Methods in the Emerging Markets", Tacoma City Light, Tacoma, Washington.
May 19, 1998	"Participation in BPA's Conscription Process: Opportunity or Extortion?", Snohomish Public Utilities Board
May 14, 1998	"FORSCOM Utility Deregulation Panel of Experts"
May 7, 1998	"Running a Competitive Bidding Program for Energy Services and Supplies", InfoCast-The Institutional Energy Users Forum, San Francisco, California
May 5, 1998	"A Revisionist's History of the Future", Tacoma City Light Board
February 19, 1998	"Selecting a Power Supplier: Fundamentals, Fundamentals, Fundamentals", LSI Conference
December 12, 1997	"Tools of the Trade: End-User Purchasing Strategies in the New Market", Energy Institute Conference, Las Vegas, Nevada
November 18, 1997	"Buying Cheap Power in California", InfoCast, Santa Monica, California
November 17, 1997	"RFP Development: A Step-by-Step Guide", AIC Conference, Chicago, Illinois
October 27, 1997	"Negotiating a Better Deal for Your Power Supply", InfoCast, Chicago, Illinois
August 14, 1997	"Selecting Aggregation Partners That Offer the Greatest Benefits", Center for Business Intelligence, Boston, Massachusetts
July 25, 1997	"Buying Cheap Power in the Northeast and Mid-Atlantic States" InfoCast, Boston, Massachusetts
June 23-24, 1997	"Negotiating A Better Deal for Your Power Supply" InfoCast, Chicago, Illinois

June 20, 1997	"Buying Cheap Power in California: Markets Meet Ab-1890", InfoCast, San Francisco, California
June 3, 1997	"How Regional Issues Have Shaped the Landscape for Tomorrow's Competition" (keynote address), Electricity Choices for Consumers
April 9, 1997	"Electric Competition", (opening presentation) at GasMart, Chicago, Illinois
May 15, 1997	"The Fifth Fiasco", Clark County PUD's Energy Symposium
April 3, 1997	"Economic Evaluations of Municipalization", InfoCast, Municipalization in a Changing Power Industry", Arlington, Virginia
January 28, 1997	"Power Supplies for New Municipals Designing an Effective RFP and Evaluating Responses"
January 20, 1997	"Clark County Utilities: A Revisionist View of the Future", Clark County Executive Retreat
January 16, 1997	"Getting the Best Deal for the Customer", Law Seminars Annual Energy Meeting
January 10, 1997	"Markets, Transmissions & Resources: Overview of the US/Canadian Power Market", Edmonton Power Authority
November 27, 1996	"Evanston Energy Supply Solutions", Energy Symposium, Evanston, Illinois
November 18, 1996	"Assessing Real Power Markets for Real Customers"
November 14, 1996	"Stakeholders under Restructuring: Return of Competition Shifts Interest of Players Dramatically", NWPPA Annual Energy Meeting
November 6, 1996	"Watching the Hippos Dance: Electricity in the 1990's"
October 28, 1996	"California Gas Forecasts Base"
October 20, 1996	"Breaking up Is Hard to Do" (restructuring the marketplace after competition), EEI Distribution Committee

September 14, 1996	"West Coast Overview: Summary of Progress in Region Retail Wheeling III", Washington, D.C.
September 7, 1996	"What Do Industrials Need?", PowerMart
August 26, 1996	"Power Supplies for New Municipals: Designing an Effective RFP and Evaluating Responses"
August 21, 1996	"Timing New Industrial Power Contracts"
June 24, 1996	"Electricity/Gas Cross Market Opportunities: Exploiting the Synergies between Gas and Electricity Will Increase the Supply of Both Commodities", InfoCast, Electric/Gas Symposium
June 5, 1996	"Lions, Tigers, and Bears: The New Zoology of the North American Electric Business", (opening presentation), PowerMart
May 17, 1996	"Sliding Towards Home: New Markets and New Prices Will Be Determined by the Customer", Northwest Pulp and Paper Association
May 10, 1996	"Fifty Ways to Leave Your Lover: Another Argument for Choosing Interruptability"
May 9, 1996	"Power Supply Option under Central Lincoln's 1981 Power Sales Contract: Competition is Keen"
April 17, 1996	"Surviving the New Industrial Markets Shifts"
March 21, 1996	"Market Fundamentals West Coast Forecast 1996-2010", Seattle City Light Senior Management
March 19, 1996	"Energy Strategies for the Turn of the Century" Weyerhauser Corporation Senior Management
February 23, 1996	"Is PoolCo Just the Status Quo?"
February 3, 1996	"Acquiring and Using a Resource Portfolio in Open Access: A Profile of Change for Large Industrial Users"
February 3, 1996	"Primary Metals: Energy Supply Case Study", Pasha Symposium on Energy Supply

February 2, 1996	"Supply Power to Industrials: Competitive Bidding", Houston, Texas
February 2, 1996	"Power Contracts: Writing the Deal"
January 26, 1996	"Western States Power Supply" (on industrial rates)
December 18, 1995	"Alberta Power Pool: 1996" (analysis of creation and implementation of the Alberta Power Pool)
December 12, 1995	"Big Rivers Electric Cooperative: A Stranded Investment Case Study" (overview, history and market value of BREC stranded investment)
December 4, 1995	"Predators and Prey: 1995 through 2010 in the WSCC" (on surplus power and plummeting natural gas prices), NELPA/ Portland State University Energy Symposium
October 18, 1995	"Teaching the Hippopotamus to Dance: Bringing the Competitive Electric Market to Evanston" (on competition in the marketplace)
October 12, 1995	"Teaching the Hippo to Dance: Negotiating With the 'New' Utility" Presentation, Pulp and Paper Association Annual Energy Meeting
October 10, 1995	"Teaching the Hippopotamus to Dance: Negotiating with a New Utility" (discussion of competition and market positioning for industry)
August 28, 1995	"Retail Wheeling as a Quid Pro Quo for Plant Location" (on competition, regulation and innovative solutions) Infocast, New York
August 20, 1995	"Restructuring in Alberta and California", Governor's Energy Symposium, Springfield, Illinois
June 22, 1995	"Bringing Ports and Utilities Together", Pacific Northwest Ports Association
June 12, 1995	"Using the 'R' Word: Bonneville's Decision to Release 4000 Megawatts to the Market", NELPA Annual Accounting Meeting
February 16, 1995	"Stranded Costs: Accountants Full Employment for the 1990's", Northwest Electric Light & Power

January 10, 1995	"Competition in the 1990s: Hard Work, Low Prices, Opportunities for Expansion", Industrial Customers of Northwest Utilities Annual Meeting
March 28, 1994	"Market Opportunities in Transmission: The Next Decade in the Pacific Northwest", NELPA