Resource Insight, Inc.

Estimation of Market Value, Stranded Investment, and Restructuring Gains

for Major Massachusetts Utilities

Prepared for the Massachusetts Attorney General

by Paul Chernick

Susan Geller

Rachel Brailove

Jonathan Wallach

Adam Auster

April 17, 1996

Table of Contents

Introduction and Summary 3

Methodology 5
- Scope 5
- Methodology 7

Attorney General's Base Case 8
- Base-Case Inputs and Assumptions 8
  - Nuclear Inputs 8
  - Non-Nuclear Inputs 9
  - Market Prices 10
- Base-Case Results 11
- Implications of Base-Case Results 13

Sensitivities 14
- Better Nuclear Performance 14
- Higher Discount Rate 15
- Lower Fuel Prices 16
- NEES Projection of Market Prices 17

Introduction and Summary

This report explores the likely range of the difference between major Massachusetts utilities' net investment in their generation facilities and the value of those facilities in a restructured industry, with a competitive market for generation capacity and energy. The utilities have claimed that their investments in generation plants exceed the market value of those plants, resulting in strandable investment, and a potential loss due to restructuring. On the other hand, if the market value exceeds the investment, the utilities will realize a gain when the plants are sold or otherwise repriced to reflect market value. While the investments are relatively easy to determine, the market values are not at all obvious.

Our objective in this study was to estimate the price that would be paid by the high bidder for each generation asset in a competitive market. In general, that high bidder would be among the organizations that believe they can operate the plant at high reliability and low cost--perhaps better than the current operator. The high bidders for each type of plant are also likely to be relatively pessimistic about competing options. For example, the high bidders for the oil- and gas-fired steam plants will generally believe that they can increase capacity at the existing units, add new units at the sites, reduce heat rates, reduce staffing, and get good prices on gas and oil;[1] they are also likely to believe that coal plants (in New England and neighboring regions) will face expensive environmental requirements, that nuclear plants will experience continuing technical, regulatory, and economic problems, and that new gas combined-cycle capacity will not be much cheaper than recent additions. The high bidders for the coal plants are likely to hold opposite beliefs on several points, believing that they can inexpensively resolve outstanding environmental issues, maintain high reliability, and that oil and gas prices will remain stable or rise, improving the economics of coal compared to existing oil- and gas-fired plants and new combined-cycle plants.[2] While using any one set of market and operating assumptions will not capture the entire range of bidder responses, we have attempted to reasonably anticipate the value placed on generation by bidders with a range of expectations.

Our results are strikingly different than the assumptions incorporated in the February 1996 restructuring filings of the major Massachusetts electric utilities, all of whom assumed that their generation assets would have zero market value in a restructured industry. As a result of this assumption, the utilities have requested stranded-investment charges that would fully cover their net investment in the plants.[3]

---

[1]Oil and gas producers may also see investments in plants powered by their fuels as hedging opportunities, since the plants will be most profitable when the company's primary product is least valuable, and vice versa.

[2]They are likely to agree with the buyers of oil- and gas-fired plants about prospects for nuclear and new combined-cycle capacity.

[3]In some cases, the proposed payments would more than cover the net investment.

In contrast, we conclude that market valuation of most utilities' generation assets will exceed their net investment, resulting in large restructuring gains to be credited to ratepayers.[4] For the Massachusetts operations of New England Power, the gain is likely to be in the range of $1 to $3 billion, while the other utilities are likely to realize gains in the hundreds of millions of dollars. Under very pessimistic conditions, some utilities may have some net stranded investment, but at only a small fraction of their total net investment. Large levels of stranded investment are the result of either poor plant performance or low market prices, either of which should also result in retirement of large amounts of capacity, regardless of industry structure. Utilities do not generally receive full cost recovery for investment in retired plants, and cannot expect the restructuring process to get them full recovery of investments in plants that should be retired today.

As demonstrated by the results in this report, the value of utility-owned power plants depends on how well they can be run (or reused) in the future, as well as the market value of power. Hence, the determination of stranded investments and restructuring gains will require either (1) divestiture through a competitive bidding process, or (2) DPU determination of many cost components (reliability, dispatch, locational generation values, operating costs, retrofit requirements, fuel prices, heat rates, market prices) under efficient management in a competitive environment.[5] Since divestiture will be very helpful (perhaps essential) in creating a working competitive market, the divestiture approach appears to be the most promising method for determining restructuring gains and losses.

Since we have not been able to obtain detailed utility data by unit on past performance, anticipated capital and operating cost requirements, regulatory restrictions, operating reserve benefits, and the like, our quantitative estimates are preliminary and subject to revision. The overall conclusions of this study appear to be quite robust under a broad range of input assumptions.

---

[4]This credit will be offset by other restructuring losses.

[5]The competitive environment may benefit plant operators, strengthening their positions in seeking reductions in costs from suppliers.

Methodology

Scope

Our analysis estimates the stranded generation investment for five of Massachusetts's investor-owned utilities: Boston Edison (BECo), Cambridge Electric, Commonwealth Electric (ComElectric), the portion of New England Electric System (NEES)'s stranded investment attributable to Massachusetts, and Western Massachusetts Electric Company (WMECo).[6]

Stranded investment was based on each utility's ownership of plants, with the following adjustments.

- Massachusetts was assigned a 74% share of NEES plant, based on the portion of NEES's 1994 Requirements Service sales to its three retail subsidiaries that went to the Massachusetts Electric Company.[7]

- The WMECo analysis reflects 100% of WMECo's own plant. Under the Northeast Utilities' Generation and Transmission (G&T) agreement, only a fraction of this plant actually serves Massachusetts ratepayers. Eliminating the portion of stranded investment that serves NU's out-of-state customers would tend to reduce the magnitude, but not change the sign, of the results described below. Massachusetts ratepayers may also be entitled to a portion of the restructuring gain by Holyoke Water Power, another Massachusetts NU subsidiary, which now sells some of its inexpensive hydro and coal generation at retail to a few industrial customers, and wholesales the rest to the other NU companies.

- Stock ownership in Maine Yankee, Vermont Yankee, and Connecticut Yankee was treated as pro rata utility ownership of capacity in this analysis.

- We allocated the resources of Canal Electric Company, the wholesale affiliate and supplier to Cambridge and ComElectric, between the two retail affiliates in proportion to their existing long-term purchases. For the remainder of the long-term sale of Canal 1 capacity to NEES and BECo through 2001, we credited Cambridge and ComElectric with NEES's projections of contract payments, rather than the market

---

[6]We have not yet performed similar analyses for Unitil's Fitchburg Gas and Electric or the Massachusetts portion of EUA's Montaup Electric.

[7]Massachusetts Electric is a retail subsidiary of NEES, whose generating assets are owned by another NEES subsidiary, the New England Power Company.

price, but ignored the short-term value or cost of the plant to the buyers.[8]

- We reduced BECo's share of Pilgrim to reflect its life-of-unit sales, and included ComElectric's Pilgrim purchase in ComElectric's resources.

- We assumed the retirement of Mystic 4–6 and Salem 1–3 prior to the start of the analysis period. We believe that the market value of Mystic 4-6 fails to cover normal O&M costs for those units, currently and on a present-value basis; such uneconomic units should be retired immediately. We have adopted NEES's planning assumption that the costs of complying with pending environmental requirements will exceed the value of Salem 1–3, leading to their retirement shortly after the assumed restructuring date. We ignored any benefits from these units, including the continued short-term operation of the Salem units between the beginning of 1998 and their planned retirement in 1999–2001.[9]

- We have ignored the value of utility-owned power plant sites (and the associated steam turbines, cooling systems, fuel supply facilities, substations, and other auxiliaries) at such steam-plant sites as Mystic, Salem, West Springfield, Cannon Street, L Street, and Edgar, as well as the sites of retired peakers and undeveloped properties.[10]

- We have considered only utility-owned generation, excluding all gains or losses from revaluation of purchases (Hydro Quebec, NUGs) at market prices, as well as potentially stranded generation-related regulatory assets, and nuclear decommissioning. We have assumed that responsibility for the adequacy of nuclear decommissioning funds will continue to rest on ratepayers (or some other broad-based and secure source) rather than on shareholders in a competitive market.

- NEES's share of Ocean States Power was not included in the analysis, although NEES is an owner of, as well as a purchaser from OSP, which should therefore be treated as a utility-owned plant obligation comparable to the Yankees.[11]

---

[8]These companies are all subsidiaries of the Commonwealth Energy System.

[9]Cost recovery for plants that are uneconomic to operate should be computed as for other early retirements. The Massachusetts Department of Public Utilities and the Federal Energy Regulatory Commission have generally split the costs of prudently abandoned plants between ratepayers and shareholders.

[10]The salvage value of retired plants can be significant. If Mystic 4-6 are repowered into a combined-cycle plant, saving just 10% of the cost of a green-field plant, their salvage value would be about $100 M.

[11]In contrast, BECo's purchase from OSP is essentially a non-utility purchase.

Methodology

Stranded investment was estimated as the difference between net plant and the present value of future operating profits, as of January 1, 1998. Net plant was estimated from data in each utility's 1994 FERC Form 1, as

- gross plant from a combination of data from pp. 402–403 (line 17) and pp. 204–205;
- plus, for the nuclear units, three years of capital additions;
- minus accumulated depreciation from p. 219, allocated to units where necessary;
- minus three years of estimated depreciation, using annual depreciation from page 336.[12]

Operating profits were calculated as the present value of the market value of energy and capacity, less annual expenditures for fuel, O&M, and nuclear capital additions (including taxes).

[12]These data sources were supplemented from other utility filings, as available. We did not net out the value of deferred income taxes, which utilities have collected from ratepayers but not paid to the government. This constitutes a significant reduction in net utility investment, amounting to about $240 million for NEES.

Attorney General's Base Case

Base-Case Inputs and Assumptions

Most inputs are specific to particular units, or groups of units. These inputs are describe below for nuclear plants, and then for non-nuclear capacity. Two assumptions apply for all plants:

- Non-fuel O&M reported for the plants was adjusted upward by 20% to account for general and administrative expenses.
- We used a discount rate of 10%, typical of (or somewhat higher than) the discount rates used in utility's own analyses. The 10% discount rate is also similar to utility embedded and marginal costs of capital.

Nuclear Inputs

With one exception, each New England nuclear unit was modeled separately. Millstone 1 and 2 were aggregated, since much of the historical data reported for them are aggregated. We projected capacity factor, non-fuel O&M, capital additions, and fuel cost for each unit.

- Capacity factors varied among the plants from 65% to 85%, reflecting recent performance by unit.
- We set annual capital additions at the average of recent costs for each unit, and continued that rate of additions through the plants' scheduled operating life.
- We assumed that each unit's recent non-fuel O&M costs would rise 1% annually in real terms.
- Nuclear fuel was assumed to cost a constant 6 mills/kWh in 1996 dollars.
- Each nuclear unit was assumed to operate until the end of its license, rounded to the nearest new year, except that Millstone 1 and 2, which were modeled together, were assumed to operate until the midpoint between their license expiration dates.[13]

Non-Nuclear Inputs

Each utility's non-nuclear generation is generally aggregated into groups by fuel-type. For each group, O&M was based on historical costs for company-owned or comparable

---

[13]In fact, Millstone 2 is not only newer than Millstone 1, it is also larger, designed and built differently, and was built at a greater cost per MW.

plants.[14] Fossil fuel prices were derived from a 1995 projection of price for southern New England utilities, prepared by Energy Ventures Analysis for the Vermont Department of Public Service. For dual-fuel plants, we assumed the average fuel price would be 90% of the price of residual oil. Estimates of O&M and capital additions were based on continuation of recent performance, and were assumed to stay constant in real terms. Capital additions are not usually significant for non-nuclear plants, and we did not model any for these resources. Fossil units are assumed to operate through 2015 (18 years from the start of the analysis period), while hydro units are assumed to operate through 2035 (38 years). Longer operation may be physically possible and economic, but is likely to require some additional investment.

- Fossil Peakers (CTs and Diesels)--Peaking capacity is treated as having no fuel costs and no energy benefits.

- Oil and Dual-Fuel Steam Plants--Most of these plants are assumed to operate at a 50% capacity factor and 10,000 BTU/kWh heat rate.[15] Canal 1, which is treated separately because of its changing ownership over time, has operated particularly efficiently and is assumed to operate at 60% capacity factor and 9368 BTU heat rate. WMECo's fossil-steam capacity (now just West Springfield 3) has high heat rates (which we project at 11,000 BTUs) and been operated less than other steam units in recent years; we assumed it would have a capacity factor of 20%.

- Coal Plants--The only coal capacity modeled, NEES's Brayton Point 1-3, is assumed to operate at an 80% capacity factor and 10,000 BTU heat rate.

- Firm Gas--Only New Boston fell into this category. Like the majority of oil and dual-fuel steam plants, it was assumed to operate at a 50% capacity factor and 10,000 BTU heat rate.

- Conventional Hydro--Each of the companies' hydro resources are aggregated and assumed to operate at historical capacity factors (27% for NEES; 49% for WMECo). However, due to limited dispatchability, they are assumed to serve in somewhat lower-cost energy periods, on average (40% and 60% load factor, respectively). We credited storage hydro O&M with $10/kW-yr. for rapid-start capability, averaging over conventional storage hydro, pumped storage on standby, and the double operating-reserve benefit of the pumped storage in pumping operation.

- Pumped-Storage Hydro--Storage facilities shift energy supplies, rather than

---

[14]For example, NEES's oil-steam units are located in the same plants as the coal plants, so NEES does not report O&M separately by fuel type. We therefore used the O&M cost for other oil-steam units, such as Canal (about $30/kW-yr.), for NEES's oil-steam capacity. The difference between this estimate for Brayton 4 and total station O&M provided our estimate of O&M for the Brayton coal plants.

[15]Cambridge Electric's cogeneration capacity serving its affiliated steam system is assumed to operate at only 30% capacity factor, reflecting its largely seasonal heating load.

generating additional electricity. We estimated the energy benefits of pumped storage by computing the value of shifting energy from the New England power Exchange's low-cost hours to its high-cost hours in 1993, reflecting typical 30% losses in pumping and generation. The sum of the energy savings over the course of the year was equivalent to the average 1993 NEPEX system lambda at an 8% capacity factor. We assumed that this relationship will continue.

Market Prices

We developed forecasts of market prices of capacity and energy. Both components are driven by the projection in the New England Power Pool's 1995 Capacity, Energy, Load and Transmission Report that New England will experience a capacity deficiency by 2003. Based on this 2003 need date, we assume that the market value of capacity will trend upwards from $10.56 in 1996 to $51.75/kW-year in 2003, the full cost of a new peaker (in real-levelized 1996 dollars).

We based our projection of the market value of energy on a starting value of $25/MWh in 1995, gradually rising to $42.75/MWh, the cost of energy from a new gas combined-cycle plant, in 2003. From 2003 on, we assume that the market value of energy will be determined by the cost of an intermediate combined cycle addition (net of the cost of new peaking capacity). To project the cost of power from that combined cycle unit, we used fuel prices from the 1995 Energy Ventures Analysis fuel price forecast. According to that forecast, interruptible gas prices will reach $2.98/MMBtu and #2 oil prices will reach $4.60/MMBtu by 2003, both in 1996 dollars.

In addition, we made the following assumptions about combined cycle cost and operation:

- a construction cost of $826/kW (in 1996 dollars);
- a fuel mix of 67% interruptible gas and 33% distillate;
- a 60% capacity factor, assuming that the unit will be dispatched much less frequently when it is operating on #2 oil;
- a heat rate of 8,374 BTU/kWh.

Marginal system operating costs vary throughout the year. In high-load periods, more-expensive plants are forced to run, and in a competitive market, this will raise the spot price for all suppliers. Among fully dispatchable plants, those with low fuel costs will run more, but will receive a lower average annual price than those with high running costs, which are only operated in the high-cost hours.

To account for this variation in market prices, we sorted 1993 hourly NEPOOL system lambdas in descending order, and calculated average lambdas for various load factors, assuming that the lowest-load-factor plants would operate in the highest-cost periods. We computed the ratio of the average system lambda at each of the load factors to the average 1993 lambda at the 60% load factor assumed for the base calculation of market value, described above. We then computed the value of the energy produced by any resource by multiplying the lambda ratio by the energy component of the base market price for each year.

For highly dispatchable plants (fossil), we assumed that the capacity factor at which they operated was determined solely by economic (rather than technical) reasons and therefor they always served the highest cost load at their capacity factor. Nuclear plants were assumed to operate as much as technically possible, and so served average cost load throughout the year. We recognized that some hydro capacity operate as highly dispatchable peakers, while the operation of other hydro capacity is essentially baseload, varying only with water conditions. We therefore valued the energy from WMECo and NEES hydro plants as if it were generated at load factors (60% and 40%) considerably greater than their capacity factors (49% and 27%).

Base-Case Results

Given the plant performance, operating costs, and market values of capacity and energy described in the previous sections, we computed the operating profit--market value minus operating costs--for each nuclear unit and each group of non-nuclear generation. These results are shown in Table 1, in the first column under each of the five utilities studied.

All of the generation assets studied produced positive present values of operating profits, except for Millstone 1 and 2 and Pilgrim.[16] With the base-case inputs, these plants are uneconomic to operate and should be retired regardless of whether the electric industry is restructured. In the base case, these plants would have no value to a potential purchaser, other than the value of the sites, and could be given away at best.

For the remaining utility-owned generation resources, the present value of the operating profit represents the market value of the plant investment. This market value may be lower than the net plant investment (gross plant minus accumulated depreciation), in which case some of the asset is a stranded investment. For other groups of resources, the market value will exceed net investment, so there is negative stranded investment, or a restructuring gain in moving the generation from the regulated to competitive markets.

At the level of resolution in our analysis, the only economic resources (that is, excluding the units that should be retired) that produce positive stranded investments are Millstone 3 and those shares of Seabrook owned by Cambridge and ComElectric.[17] The Yankees, NEES's share of Seabrook, and each utility's groups of fossil steam plants,

---

[16]Due to lack of data on cost and performance by unit, we were not able to determine the cost-effectiveness of individual units; additional analysis would be required to determine whether Millstone 1 and 2 are both uneconomic. As for the fossil units whose retirement we assumed (Mystic 4-6 and Salem 1-3), the recovery of the costs of retired nuclear units should be considered separately from the effects of restructuring.

[17]NEES's share of Seabrook has very little remaining capital cost, due to earlier write-offs.

combustion turbines, and hydro plants each produce a restructuring gain.[18]

More importantly, each utility's generation assets as a whole are worth more than the net investment, producing a restructuring gain. The net profit expected from selling generation at market prices would be $250–$500 million for each of the utilities, except for NEES at about $2.7 billion. NEES's restructuring gain is much larger than the other utilities because (1) it is simply a larger utility, with more generation assets; (2) its nuclear assets would produce a small gain, with Maine Yankee, Vermont Yankee, and its written-down Seabrook share more than offsetting its Millstone 3 share; and (3) its large hydro resources are very valuable.[19]

Implications of Base-Case Results

The results described in the preceding section imply that, in a functional competitive market, potential owners of the generation plants now owned by the Massachusetts utilities would pay more for the plants than the utilities' net investment, producing a gain from restructuring. This gain is due to the depreciation and operating costs the ratepayers have paid over the plants' lives.

In order for the restructuring gain estimated in this analysis to be realized, there must be several competing bidders for each resource, who believe (roughly speaking) that

- the performance and costs of the plants (under the bidder's ownership) can continue at historical levels,
- market values of capacity and energy will bear the same relationship to the plants' operating costs as described above, and
- they can finance the plants at costs similar to utility costs of capital.

---

[18]The restructuring gain, and indeed the cost-effectiveness of continued operation, are contingent on cost and performance comparable to historical values. For the older nuclear units in particular, new large capital requirements could make continued operation uneconomic.

[19]Similarly, WMECo's hydro capacity is responsible for all of its restructuring gain, and for offsetting the stranded Millstone investments.

Sensitivities

We varied a number of the Base Case assumptions, to determine how sensitive our estimates of restructuring gain are to those assumptions. First, we considered the effects of improving nuclear performance, if other owners or the incentives of the competitive environment allow under-performing New England nuclear units to perform more like the industry leaders. Second, we increased the discount rate to reflect the possibility that non-utility owners of generation in a competitive environment would have higher financing costs than the utilities.[20] Third, we tested the sensitivity of our conclusions to fuel prices, reducing the projection of market prices and plant fuel costs by using NEES's projected fuel costs. Finally, we used NEES's extremely unfavorable market price projection.

Better Nuclear Performance

This scenario modeled nuclear-plant costs and performance from past utility projections and the performance of comparable well-operated plants, approximating the results an enthusiastic purchaser might expect from the plants under new ownership in a competitive environment.

The capacity factors for the worst historical performers, Millstone 1 and 2 and Connecticut Yankee, were increased to the 74% availability projected by NEPOOL's Generation Task Force and used as NEPOOL's target unit availability for these units. The best performers, Maine Yankee and Vermont Yankee, were assumed to maintain their past performance at approximately 80% and 85% capacity factors, respectively. Millstone 3 and Seabrook were projected to come up to the 80% level of Maine Yankee (another large PWR), while Pilgrim was assumed to operate at 84%, based on BECo's projections and Vermont Yankee's performance.[21]

For O&M and capital additions, we assumed that

- the low-cost unit (Maine Yankee) would continue at its base-case expenditure levels,
- Millstone-3 and Seabrook costs would fall to Maine-Yankee costs per kilowatt,
- Millstone-1-and-2 costs would approximate those recently projected by NU,

---

[20]The higher discount rate could also reflect the tax burden of financing, net of the tax benefits of accelerated depreciation. BECo estimates its "tax-affected" cost of capital to be 11.61%.

[21]Vermont Yankee and Pilgrim are similar in age, size, and technology.

- Pilgrim costs would fall to the level assumed by BECo in its last IRM filing.[22]

We also assumed no annual real escalation in O&M (compared to 1% per year assumed in the Base Case).

With this improved operating performance, nuclear operating profit would increase, as shown in Table 2. Operating profit becomes positive for all nuclear units. In addition to the Yankees and NEES's Seabrook share, which produced restructuring gains in the base case, improved performance yields restructuring gains from Pilgrim, Millstone 1 and 2, and WMECo's Millstone-3 share.[23] At first glance, it may seem surprising that Pilgrim and Millstone 1 and 2 move so easily from being uneconomic to operate at base-case performance, to producing a restructuring gain with good performance. This reversal results from the fact that these older nuclear units have fairly low net investments; if they are economic to operate, they need not produce a very large operating profit to create a restructuring gain.

As a result of the improved nuclear performance, there is a restructuring gain for each utility's nuclear investment (except for ComElectric's) and the total gains increase for each utility. The improvements are most dramatic for Boston Edison (for which the restructuring gain rises to nearly $800 million) and WMECo ($700 million).

Higher Discount Rate

Higher discount rates will generally result in lower present values of operating profits, and thus higher stranded investment or lower restructuring gains. We reevaluated the Base Case and Good Nuclear Performance Case for a 15% discount rate.

With this higher discount rate, the restructuring gains decline compared to the Base Case for all utilities, as shown in Table 3. NEES's restructuring gain falls from $2.7 billion to $1.5 billion, while the other utilities' gains fall from around $300 million each to

- about $200 million restructuring gain for each of Cambridge and ComElectric,
- break-even for WMECo ($6 million in stranded investment out of $450 million in net plant), and
- a modest amount of stranded investment for BECo ($126 million stranded out of $1 billion in net plant).[24]

---

[22]As a result of this assumption, Millstone 1 and 2 and Pilgrim cost projections move substantially towards Maine Yankee costs, but remain considerably higher.

[23]WMECo has a lower booked cost per kW for Millstone than does NEES.

[24]These small stranded investments result from the costs of the plants that are uneconomic to operate with or without

Good nuclear performance would result in all the nuclear capacity being cost-effective to continue operating, even with the higher discount rate, and significant restructuring gains for all the utilities. These results are summarized in Table 4.

Lower Fuel Prices

We re-estimated our projection of the market value of energy substituting lower NEES fuel-price projections. We made two other modifications to our projections for the new marginal combined-cycle capacity, both of which result in a lower market value of energy. First, we changed the fuel mix to 80% interruptible gas and 20% distillate. Second, consistent with the change in fuel mix, we assumed that the unit would operate at a higher capacity factor of 65%. We also used NEES's fuel-price projections for the cost of generation at existing fossil units.

According to the 1995 NEES IRP, interruptible gas prices will be $2.32/MMBtu and #2 oil prices will be $4.37/MMBtu by 2003, 22% and 5% lower, respectively, than the EVA gas and oil price projections. The two fuel price forecasts diverge substantially in later years because NEES projects zero real price escalation after 2001.[25]

We performed this sensitivity only for NEES, with other inputs from the Base Case. As summarized in Table 5, the operating profits decline for all resources. Connecticut Yankee, whose operation was only marginally cost-effective in the Base Case, is uneconomic with NEES fuel costs. NEES's restructuring gain declines only about 20%, from $2.7 to $2.2 billion.

NEES Projection of Market Prices

NEES has sponsored the lowest projection of market prices filed in the Massachusetts restructuring process. The projection starts in 1998 at $25/MWh (1996 dollars), not much higher than March 1996 spot energy prices (without capacity); rises gradually to about $33/MWh in 2006, and remains roughly steady thereafter.[26] This projection is supplied only as an aggregated annual dollars-per-MWh value of baseload NUG generation. To be useful in valuing utility-owned generation, market price projections must reasonably reflect the value of capacity, as well as energy for a variety of load factors. To split NEES's aggregate

---

restructuring, and regardless of which discount rate is applied. The higher discount rate does not change the list of uneconomic nuclear units, although Connecticut Yankee's already-thin profit margin virtually disappears at the higher discount rate. As noted above, these costs are not stranded by restructuring, and should dealt with separately from restructuring gains and losses.

[25]These projections are set forth in Table 5.2, p. 5-3 of NEES's June, 1995 update to its IRP.

[26]See MDPU No. 96-25, Exhibit of Michael Jesanis (MEJ-10), "MDPU Schedule Illustrating Stranded-Cost Recovery Mechanism."

projection between energy and capacity, we scaled down the market price projections described in the previous subsection, "Lower Fuel Prices," so that the resulting capacity and energy values for each year would be consistent with NEES's projection at a 100% load factor. While we do not know how NEES estimated market prices, we assumed that they were intended to be consistent with NEES's recent fuel forecasts, and used those fuel prices for the fossil units.

We tested the effects of these market prices for all five utilities. With base nuclear performance, as shown in Table 6,

- all nuclear units other than Maine Yankee are uneconomical to operate and should be retired immediately;
- continued operation of WMECo's fossil capacity (West Springfield 3) is uneconomic;
- aggregate operating profit from NEES oil/gas steam is paper-thin, suggesting that at least some of this generation (probably Salem 4) would be retired;
- WMECo, ComElectric and BECo are left with some stranded investment, ranging from 40% to 70% of their net generation investment, largely due to the retirement of the nuclear units;[27] but
- NEES still has a restructuring gain of over $350 million, and Cambridge has a small gain as well.

This outcome is very unlikely. Market prices low enough to result in retirement of most of New England's nuclear generation, as well as many older fossil units, would be difficult to maintain.[28] The costs of new generation will have to fall considerably to produce long-term market prices in the 3.2¢/kWh range projected by NEES.

Even with good nuclear performance (Table 7), Connecticut Yankee, Vermont Yankee, and Millstone 1 and 2 are still unprofitable to operate at the market prices projected by NEES.[29] Stranded nuclear investments remain large, preventing any dramatic decline in stranded investment for BECo or ComElectric, although WMECo's total stranded investment would drop to about 20% of its net investment. NEES and Cambridge restructuring gains rise, with NEES's gain reaching $480 million.

---

[27]As noted above, the utilities would not normally recover all the cost of abandoned generation.

[28]Market prices would also have to be similarly low in New York, PJM, and other potential power supply areas (which now have short-run market energy prices lower than New England's), resulting in similar retirements there, and a need for new capacity throughout the Northeast.

[29]Since only nuclear performance changes, the economics of Salem 4 and West Springfield 3 do not improve.