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An Analysis Based on Japanese Data

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CO_2 Abatement by Multi-fueled Electric Utilities: An Analysis Based on Japanese Data

A. Denny Ellerman[*] and Natsuki Tsukada[†]

Abstract

Multi-fueled electric utilities are commonly seen as offering relatively greater opportunities for reasonably priced carbon abatement through changes in the dispatch of generating units from capacity using high emission fuels, coal or oil, to capacity using lower emitting fuels, natural gas (LNG) or nuclear. This paper examines the potential for such abatement using Japanese electric utilities as an example. We show that the potential for abatement through re-dispatch is determined chiefly by the amount of unused capacity combining low emissions and low operating cost, which is typically not great. Considerably more abatement potential lies in changing planned, base load, fossil-fuel fired capacity additions to nuclear capacity. Our results are at odds with the common view that the demand for natural gas or LNG would increase, or at least not fall, as the result of a carbon constraint; and our analysis suggests that this result may not be limited to Japan.

Contents

1. INTRODUCTION

Electric utilities are commonly seen as a sector of the economy that can provide a more than proportionate share of CO_2 emission reductions. For instance, a study undertaken by the Japanese Ministry for Economy, Trade and Industry (METI, the former MITI) indicates that a cost-effective reduction of emissions sufficient for Japan to meet its target in the Kyoto Protocol of limiting CO_2 emissions to 6% below the 1990 level would call for electric utilities, which account for approximately one-fourth of CO_2 emissions in Japan, to reduce emissions to 9% below 1990, which implies that other sectors would reduce to 5% below the 1990 level.[Reference 1]

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Although particularly relevant for the example we explore, this study is by no means unusual. Most models predict that, for any given level of carbon abatement, a greater share will come from the electric utility sector than other sectors of the economy.

The expectation that the electric utility sector can undertake more abatement than other sectors reflects a widely held presumption that greater opportunities for low cost abatement exist in this sector because electrical networks can switch generation from higher to lower CO_2-emitting units. The expectation is that the dispatch order of the electrical system would shift from relatively higher emitting coal or oil-fired generating units to low-emitting natural gas-fired or nuclear units. Such re-dispatch would incur added fuel and transmission costs, on the assumption that the system is currently dispatched according to least-cost, but no capital expenditure would be required. Furthermore, even though retrofitting an existing, high-emitting plant, or even replacing it, to burn lower-emitting natural gas would incur capital costs, the low capital costs associated with the generation of electricity by natural gas would seem to make retrofitting, and perhaps even replacement, attractive alternatives.

This paper examines the availability and cost of potential CO_2 abatement by changing fuel use in the electric utility sector based loosely on Japanese data. The methodology is a simple one whereby we use the capital and fuel costs of the different generating options, as well as existing and planned capacity and utilization, to estimate the cost and quantity of CO_2 abatement that can be obtained from the modeled electric utility sector. This approach allows us to elaborate the basic trade-offs from a more familiar and practical perspective. The summary result is a set of marginal abatement cost schedules that indicate the cost and availability of CO_2 abatement by changing fuel use in an electric utility sector resembling that of Japan. Our intent is not to replicate the complex operating details of the electrical system, but to elucidate the general conditions governing economic abatement of CO_2 emissions in the electric utility sector, whether in Japan or elsewhere.

The next section of the paper explains the methodology and basic data while examining the current potential for carbon abatement in the Japanese electric utility sector, as if the requirement to abate emissions were imposed without any notice and corresponding opportunity to change the capital stock. Then, in the following chapter, we look forward ten years and consider how the abatement possibilities are changed, if at all, by announced construction plans and predicted utilization of the capacity expected to be in place then. In this section, we expand the discussion to consider how changing the fuel characteristics of planned capacity additions alters the abatement possibilities. We also conduct some simple sensitivity analyses of the results arising from the base case. Finally, the concluding chapter of the whole paper presents the principal insights from the paper.

2. METHODOLOGY AND DATA CONCERNING CURRENT ABATEMENT POSSIBILITIES

2.1 Features of the Model Utilities

Throughout the paper, abatement possibilities are discussed both in the aggregate and disaggregated into four companies that differ in the composition of their generating plant. These four utilities are representative of the structure of generation in Japan as a whole and they reflect the diversity of generating capacity among Japanese utilities. In the interest of verisimilitude, they are modeled to represent four utilities in Japan, which we label A, B, C, and D in order to keep the focus on what is important, namely, the fuel attributes of their capacity and generation, instead of on their identity, although the latter will be evident to anyone familiar with the Japanese electric utility sector.

The generating capacity of these four utilities in 1997, individually and in the aggregate, is shown in **Table 2.1** by fuel type: oil, coal, LNG (both simple cycle, LNG1, and combined cycle, LNG2), and nuclear. We do not include hydroelectric capacity in the belief that it is either fully dispatched or limited by hydrological conditions in its ability to be re-dispatched. We also do not include the small amount of wind, geothermal, or waste fuel power generating capacity in Japan for the same reasons, nor the considerable amount of self-generation by industrial enterprises (approximately 10% of the total in Japan) because it is outside of the electrical dispatch system.

Table 2.2 provides the utilization of the different generating capacity in 1997. Nuclear and coal generation units are the most intensively used, followed by the liquefied natural gas units, and oil-fired units. Since we do not have the actual data to identify the capacity factor for LNG1 (simple cycle) and LNG2 (combined cycle), we assume that the LNG2 is used more intensively than LNG1 because of its greater efficiency, and we assign LNG2 a uniform capacity factor of 60% for all utilities having LNG2 capacity and calculate LNG1 utilization as a residual given this assumption and the observed 1997 use of LNG by the utility. Multiplying the cells in Table 2.1 by those in Table 2.2 (times 8,760 hours in a year) yields generation in 1997 by utility and fuel as given in **Table 2.3**.

We use 1997 data because it was the latest year for which complete data were available when this study was initiated. Also, this year reflects Japanese electric utility fuel utilization and emissions as it existed at the time the Kyoto Protocol was negotiated and before the oil and LNG price collapse of 1998 or the much higher oil and LNG prices now prevailing.

Table 2.1 Generation Capacity to each of the Utility (MW^e, 1997) [2]

Utility	A	B	C	D	Total
Oil	9,200	7,780	11,880	—	28,860
Coal	—	2,100	—	5,640	7,740
LNG1[a]	17,789	7,741	6,702	—	32,232
LNG2[b]	4,800	3,860	1,340	—	10,000
Nuclear	17,310	3,620	9,770	—	30,700
Total	49,099	25,101	29,692	5,640	109,532
Total for Japan *(excluding hydro, wind & self-generation)*					173,490
Ratio of the model utilities to the total for Japan					63.1%

[a] simple cycle, [b] combined cycle

Table 2.2 Utilization of the different Generating Capacity (% of 8,760 hours, 1997) [3]

Utility	A	B	C	D
Oil	37%	28%	16%	—
Coal	—	87%	—	71%
LNG1	46%	41%	42%	—
LNG2	60%	60%	60%	—
Nuclear	80%	83%	84%	—

Table 2.3 Generation for each of the Utility (MWh, 1997) [3]

Utility	A	B	C	D	Total
Oil	29,819,040	19,082,784	16,651,008	—	65,552,832
Coal	—	16,004,520	—	35,078,544	51,083,064
LNG1	71,682,554	27,802,576	24,657,998	—	124,143,128
LNG2	25,228,800	20,288,160	7,043,040	—	52,560,000
Nuclear	121,308,480	26,320,296	71,891,568	—	219,520,344
Total	248,038,874	109,498,336	120,243,614	35,078,544	512,859,368
				Total for Japan *(excluding hydro, wind, and self-generation)*	831,300,000
				Ratio of the model utilities to the total for Japan	61.7%

2.2 CO_2 Emissions

The CO_2 emissions by operation from oil, coal, LNG1, LNG2 and nuclear power plants are given in **Table 2.4**. These data include the life-cycle emissions for each fuel choice, which is the reason the nuclear option has a small but positive amount of CO_2 emissions per kilowatt-hour.

Given the structure of generation by fuel (Table 2.3) in 1997, CO_2 emissions from the four utilities can be calculated by fuel and in total, as shown in **Table 2.5**.

Table 2.4 CO_2 Emissions of Power Plants [4]

Type	**CO_2 emissions** (g-C/kWh)
Coal	270
Oil	200
LNG1	178
LNG2	139
Nuclear	6

Table 2.5 CO_2 emissions for each of the Utility (t-C, 1997)

Utility	A	B	C	D	Total
Oil	5,963,808	3,816,557	3,330,202	—	13,110,566
Coal	—	4,321,220	—	9,471,207	13,792,427
LNG1	12,759,495	4,948,858	4,389,124	—	22,097,477
LNG2	3,506,803	2,820,054	978,983	—	7,305,840
Nuclear	727,851	157,922	431,349	—	1,317,122
Total	22,957,957	16,064,612	9,129,657	9,471,207	57,623,433

2.3 Generation Cost

The cost of CO_2 abatement through change in dispatch depends on differences in generation cost, so that the first step is calculating generation cost for the different generating options, which we do using the following equation.[3]

$$I = \frac{C\gamma}{8{,}760L} + \frac{0.86f}{\eta} \tag{2.1}$$

where I : Generation Cost per kWh (yen)
C : Construction Cost per kW^e (yen/kW^e)

γ : Annual capital charge rate (interest depreciation and O&M) (%)
L : Capacity factor (%)
f : Fuel price per unit of heat (yen/10^3 kcal)
η : heat efficiency (%)
0.86: inverse factor converting kilo-calories into kilowatt-hours assuming no heat loss
(1 kcal = 4.184×10^3 J = 1.162×10^{-3} kWh)

Total generating cost consists of two components in equation 2.1: fixed cost, the first term of the right hand side, and variable cost, dependant mainly on fuel, which is the second term. These components are then determined by inserting the values given in **Table 2.6**, which are representative of Japan in 1997, into Eq. 2.1, as is done for oil generation in Eq. 2.2 below.

$$\begin{aligned} I(\text{oil}) &= \frac{C\gamma}{8{,}760L} + \frac{0.86f}{\eta} \text{ (yen/kWh)} \\ &= \frac{206{,}000 \times 13.27\%}{8{,}760L} + \frac{0.86 \times 1.607307}{39.98\%} \text{ (yen/kWh)} \\ &= \frac{206{,}000 \times 13.27\%}{8{,}760L} + 3.457 \text{ (yen/kWh)} \end{aligned} \tag{2.2}$$

Re-dispatching existing plants changes the capacity factors for the different fuels and the implied unit fixed costs for power plants using these fuels; however, where fixed costs are recovered through the regulatory system, as is the case in Japan, these changes in implied unit fixed cost do not affect marginal decisions. Accordingly, we focus only on the variable costs, which are mostly fuel costs. We also make the reasonable assumption (for a small island country that imports all of its fuel) that fuel costs are approximately equal for the four model utilities in our simulation. The resulting marginal costs of dispatch for the five fuel options are given in **Table 2.7** from highest to lowest variable cost.

Table 2.6 Generation Cost Input Data [3], [5], [6]

Code	Unit	Oil	Coal	LNG1	LNG2	Nuclear
C	yen/kWe	206,000	304,000	214,000	232,000	377,000
γ	%	13.27	13.30	14.23	14.23	15.01
f	yen/10^3 kcal	1.607307 [a]	0.899545 [b]	1.795355 [c]	1.795355 [c]	0.802326 [d]
η	%	39.98	39.10	40.00	50.00	34.50

[a] energy content: 9,420kcal/l; f = 15.141(yen/l)/9,420(kcal/l) = 1.607307 (yen/10^3 kcal) = US$3.38/mmBtu
[b] energy content: 6,590kcal/kg; f = 5.928(yen/kg)/6,590(kcal/kg) = 0.899545 (yen/10^3 kcal) = US$1.89/mmBtu
[c] energy content: 13,010kcal/kg; f = 23.358(yen/kg)/13,010 (kcal/kg) = 1.795355 (yen/10^3 kcal) = US$3.77/mmBtu
[d] calculating inversely from putting the fuel cost constant to 2 yen/kWh

Table 2.7 Marginal Cost of Dispatch for the Fuel

Fuel	**Marginal Cost** (yen/kWh)
LNG1	3.860
Oil	3.457
LNG2	3.088
Nuclear	2.000
Coal	1.979

2.4 CO_2 Abatement Cost through Change in Dispatch

To obtain CO_2 abatement cost through change in dispatch, the differences in variable cost from Table 2.7, will be divided by the relevant difference of the CO_2 emissions as shown in Table 2.4, and then multiplied appropriately to express the result in metric tons of carbon (t-C). **Table 2.8** states the ten feasible re-dispatch options and gives the differences in emissions and variable cost for each option. For instance, re-dispatching a kilowatt-hour of oil-fired generation to simple cycle natural gas-fired generation, as represented in the first row of Table 2.8 below, reduces CO_2 emissions from 200 grams of carbon per kWh to 178, or by 22 g-C/kWh, while increasing fuel costs from 3.457 yen per kWh to 3.860, or at a cost of 0.403 yen/kWh.

Half of the re-dispatch possibilities show negative changes in variable cost, which implies cost savings by switching to lower carbon dispatch. Since generating units are dispatched on a least-cost basis in Japan, these cost savings are likely to be non-existent. A more realistic assumption would be to assume that location and network considerations create costs that are not observed in a comparison based on fuel costs alone. These costs are not infinitely high and at some additional cost, epsilon, denoted ε, more of the lower carbon generating capacity could be used. A full system dispatch model would be required to estimate epsilon and it would likely vary depending on the particular re-dispatch and the system characteristics. In the absence of such information, we adopt a uniform value of 0.50 yen/kWh. In practice, the network charge will be very low for some re-dispatch and prohibitive for other re-dispatch. Our uniform charge should be thought of as an average kWh cost at which all the relevant generation could be re-dispatched. Since this value would apply for all re-dispatch from the assumed baseline least-cost case, we apply this factor to every re-dispatch possibility in Table 2.8. Thus, the positive cost incurred in re-dispatch will be epsilon where the fuel cost increment in Table 2.8 is negative and epsilon plus the fuel cost increment where the latter is positive.

With an assumption about the value of epsilon, the variable cost differences given in Table 2.8 can be recalculated to yield positive values. Dividing these cost differences by the corresponding differences in emissions and multiplying appropriately gives abatement costs per ton of carbon (t-C) as shown in **Table 2.9**. Thus re-dispatching a kilowatt-hour from coal to LNG2 incurs a cost of 1,609 yen and saves 131 grams of carbon (g-C). At this latter rate, it would take 7,634 kilowatt-hours of re-dispatching to abate a ton of carbon so that the resulting

Table 2.8 Dispatch Options

Dispatch Option	CO_2 emissions abatement (g-C/kWh)	Variable Cost difference (yen/kWh)
(1) Oil → LNG1	22	0.403
(2) LNG1 → LNG2	39	–0.772
(3) Oil → LNG2	61	–0.369
(4) Coal → Oil	70	1.478
(5) Coal → LNG1	92	1.881
(6) Coal → LNG2	131	1.109
(7) LNG2 → Nuclear	133	–1.008
(8) LNG1 → Nuclear	172	–1.860
(9) Oil → Nuclear	194	–1.457
(10) Coal → Nuclear	264	0.021

Table 2.9 Marginal Abatement Cost through Change in Dispatch

Dispatch Option	Utility A (yen/t-C)	Utility B (yen/t-C)	Utility C (yen/t-C)
(1) Oil → LNG1	41,045	41,045	41,045
(2) Coal → Oil	—	28,257	—
(3) Coal → LNG1	—	25,880	—
(4) LNG1 → LNG2	12,821	12,821	12,821
(5) Coal → LNG2	—	12,282	—
(6) Oil → LNG2	8,197	8,197	8,197
(7) LNG2 → Nuclear	3,759	3,759	3,759
(8) LNG1 → Nuclear	2,907	2,907	2,907
(9) Oil → Nuclear	2,577	2,577	2,577
(10) Coal → Nuclear	—	1,973	—

per ton cost is 12,282 yen, as given in the fifth line of Table 2.9, and similarly there for all other options available to the three utilities with re-dispatch options. Utility D is not shown because in 1997 it is generating electricity only from coal and has no re-dispatch opportunities. Also, since utilities A and C have no coal-fired generation in 1997, they do not have the choice of switching generation from coal to lower emitting fuels.

Table 2.9 presents the cost of various re-dispatch options, but the ability of a utility to utilize any option is constrained by existing capacity and the utilization of that capacity. In particular, the extent to which re-dispatch can be accomplished for any option depends on 1) the amount of unused generating capacity of the lower emitting fuel and the maximum feasible utilization of this unused capacity, and 2) the amount of generation by the higher emitting fuel and the minimum utilization requirements for this capacity. For the sake of illustration, we assume that the maximum utilization of any generation option is 90% and that 10% represents a minimum required for maintaining the reliability of the exiting network. Using these assumptions and the data on existing capacity and utilization from Tables 2.1 and 2.2, the re-dispatch potential for each of the three utilities is given in **Table 2.10**. Since switching would occur away from coal or oil to nuclear and LNG2, the former are indicated by negative numbers, reflecting the difference from existing generation to the assumed 10% minimum, and the former are positive numbers, reflecting the difference from existing generation to the assumed 90% maximum.

Thus, for utility A, increasing the dispatch of existing nuclear capacity from the 80% utilization observed in 1997 to 90%, or by 10 percentage points, allows 15.16 TWh of re-dispatch in favor of the lowest emitting capacity on this system. Conversely, backing off the oil-

Table 2.10 Switching ability through Change in Dispatch

Utility	A		B		C	
	change in utilization	*Gigawatt-hours*	*change in utilization*	*Gigawatt-hours*	*change in utilization*	*Gigawatt-hours*
Oil	–27%	–21,760	–18%	–12,268	–6%	–6,244
Coal	—	0	–77%	–14,165	0%	0
LNG1	–36%	–56,099	–31%	–21,021	–32%	–18,787
LNG2	+30%	12,614	+30%	10,144	30%	3,522
Nuclear	+10%	15,164	+7%	2,220	6%	5,135

fired generation from the 37% utilization observed in 1997 to 10% provides 21.8 TWh of higher emitting generation that could be re-dispatched. As is readily evident from Table 2.10, there is more high-emitting generation available for re-dispatch than there is unused low-emitting capacity to which the re-dispatch could be effected.

Retrofitting existing plants to burn lower emitting fuels, as opposed to re-dispatching existing capacity, is not likely to be an attractive option. The cheapest abatement through re-dispatch in Table 2.9 occurs by moving from any fossil fuel to nuclear, and nuclear technology cannot be retrofitted onto a fossil-fuel fired plant. Coal and oil-fired plants have been retrofitted to burn natural gas, but none of these options are especially attractive even without consideration of the capital costs associated with a retrofit. For instance, even assuming that retrofit costs for LNG2 were as low as 10% of the costs of a new plant, retrofitting an oil unit being dispatched at 37% for an LNG2 application would cost 16,393 yen/t-C additional for a total cost of approximately 24,500 yen/t-C and retrofitting a coal plant running at 75% in the same manner would add 7,634 yen/t-C for a total cost of approximately 20,000 yen/t-C. Accordingly, we do not further consider retrofitting as an economically attractive option.

2.5 CO_2 Marginal Abatement Cost Schedule

The calculation of marginal abatement schedules for re-dispatch of existing generating capacity follows directly from the data given above. Where several options compete for unused low carbon capacity, the cheapest option is chosen until all possible re-dispatch is performed. The results are shown in **Table 2.11** through **Table 2.13** for utilities A, B, and C respectively. Given the 1997 pattern of generation and capacity and the assumptions we have used, each of these three utilities could abate at most between 12.8% and 15.8% of its 1997 CO_2 emissions by re-dispatching existing capacity. For utility D, there is no option to abate the CO_2 through change in dispatch. Consequently, taking the four utilities as a whole, the maximum amount of abatement available through re-dispatch is 12.4%.

By plotting the data for the marginal cost in Tables 2.11 to 2.13, we obtain **Figure 2.1** through **Figure 2.3** respectively. And by adding these up, we get **Table 2.14** and **Figure 2.4** for the aggregate abatement schedule.

One feature emerges clearly from this data: the cost and quantity of abatement available through re-dispatch is largely determined by the availability of unused nuclear capacity. As shown in Tables 2.11 through 2.14, all of the low-cost options (< 5,000 yen/t-C $\approx$ US$ 42/t-C @ 120 yen/US$) are associated with re-dispatch from fossil-fired to nuclear power. Once the unused nuclear capacity is fully utilized, the other re-dispatch options are several multiples more expensive.

The amount of cheap abatement available to each utility depends greatly on the capacity configuration and utilization of each utility. Utilities A and C have greater amounts of relatively cheap abatement available because of their greater reliance on nuclear generation (48% and 60% of total generation, respectively). In contrast, utility B, which is the only one capable of exercising the cheapest abatement option through re-dispatch, from coal to nuclear, has relatively little cheap abatement available to it because of its lower reliance on nuclear generation (24% of total generation). All three are capable of reducing emissions by 10% through re-dispatch, but the difference in capacity utilization creates a ten-fold difference in the marginal cost of doing so: approximately 2,600 yen/t-C for utilities A and C and 25,900 yen/t-C for utility B.

The option of switching from coal to natural gas fired generation would seem to be attractive, but it is a costly proposition both because natural gas is a more expensive form of generation in Japan (even in combined cycle mode) and the abatement per re-dispatched kilowatt-hour is half or less of what is possible from switching from almost any fossil fuel to the virtually no-carbon nuclear power. In fact, as shown by this example, existing combined cycle capacity would be used first for re-dispatch from oil, not coal, because the fuel cost penalty is much less.

Table 2.11 Utility A Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Oil → Nuclear	Oil (37%→18%)	Nuclear (80%→90%)	2,970,621	2,577
Oil → LNG2	Oil (18%→10%)	LNG2 (60%→75%)	393,289	8,197
LNG1 → LNG2	LNG1 (46%→42%)	LNG2 (75%→90%)	243,097	12,821
		Total abatement	3,607,007	

Table 2.12 Utility B Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Coal → Nuclear	Coal (87%→75%)	Nuclear (83%→90%)	582,785	1,973
Oil → LNG2	Oil (28%→13%)	LNG2 (60%→90%)	623,598	8,197
Coal → LNG1	Coal (75%→10%)	LNG1 (41%→59%)	1,100,081	25,880
Oil → LNG1	Oil (13%→10%)	LNG1 (59%→62%)	44,981	41,045
		Total abatement	2,351,445	

Table 2.13 Utility C Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Oil → Nuclear	Oil (16%→11%)	Nuclear (84%→90%)	1,009,467	2,577
Oil → LNG2	Oil (11%→10%)	LNG2 (60%→69%)	63,482	8,197
LNG1 → LNG1	LNG1 (42%→38%)	LNG2 (79%→59%)	91,587	12,821
		Total abatement	1,164,536	

Table 2.14 Aggregate Marginal Abatement Cost

Dispatch Option	**Marginal Cost** (yen/t-C)	**CO_2 Abatement** (t-C)
Coal → Nuclear	1,973	582,785
Oil → Nuclear	2,577	3,980,088
Oil → LNG2	8,197	1,080,369
LNG1 → LNG2	12,821	334,684
Coal → LNG1	25,880	1,100,081
Oil → LNG1	41,045	44,981
	Total Abatement	7,122,988

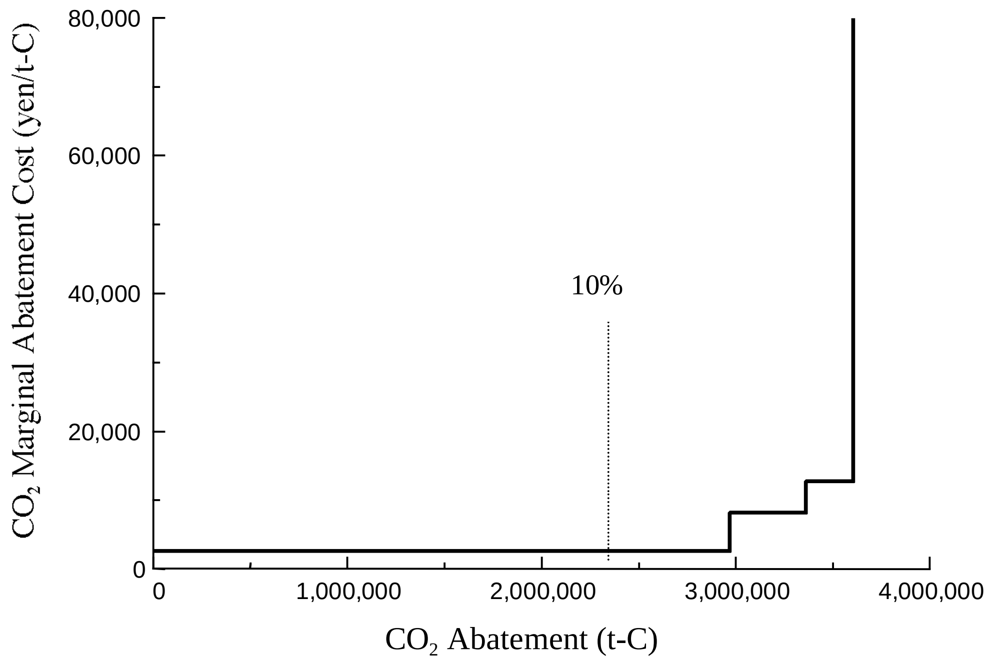

Figure 2.1 Utility A Marginal Abatement Curve

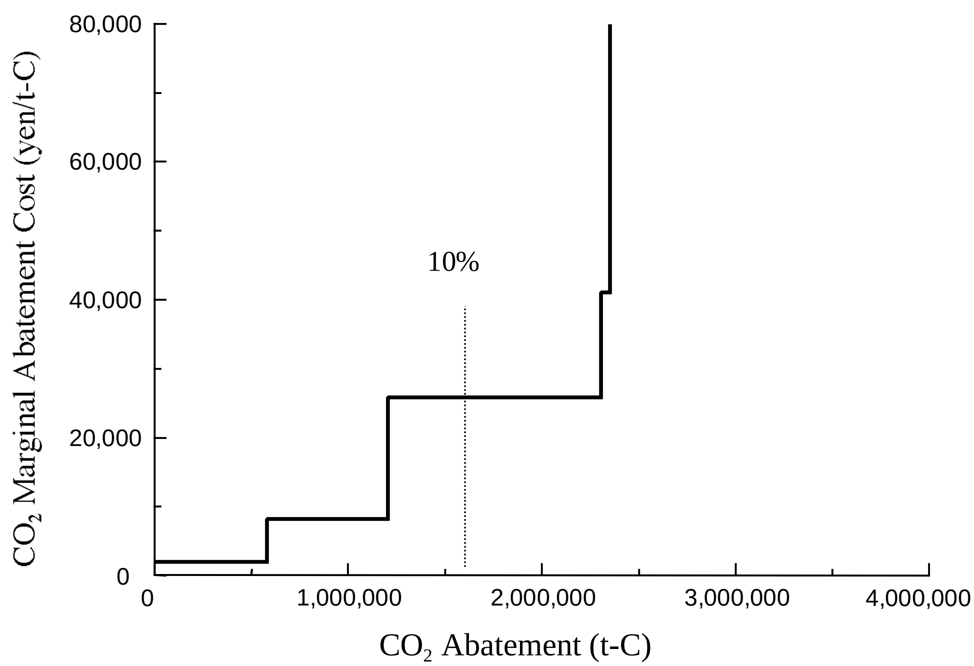

Figure 2.2 Utility B Marginal Abatement Curve

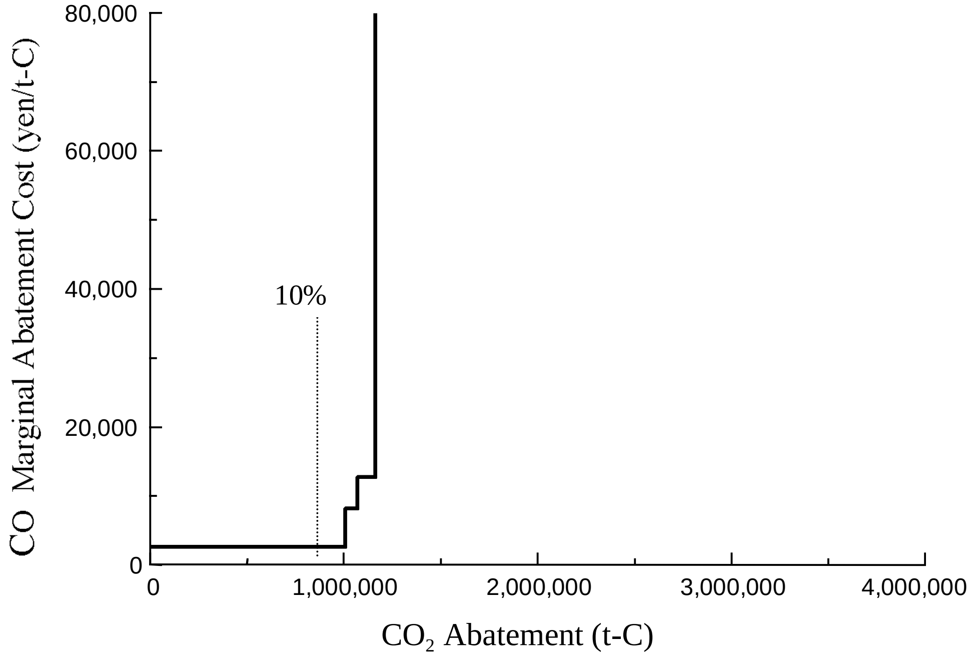

Figure 2.3 Utility C Marginal Abatement Curve

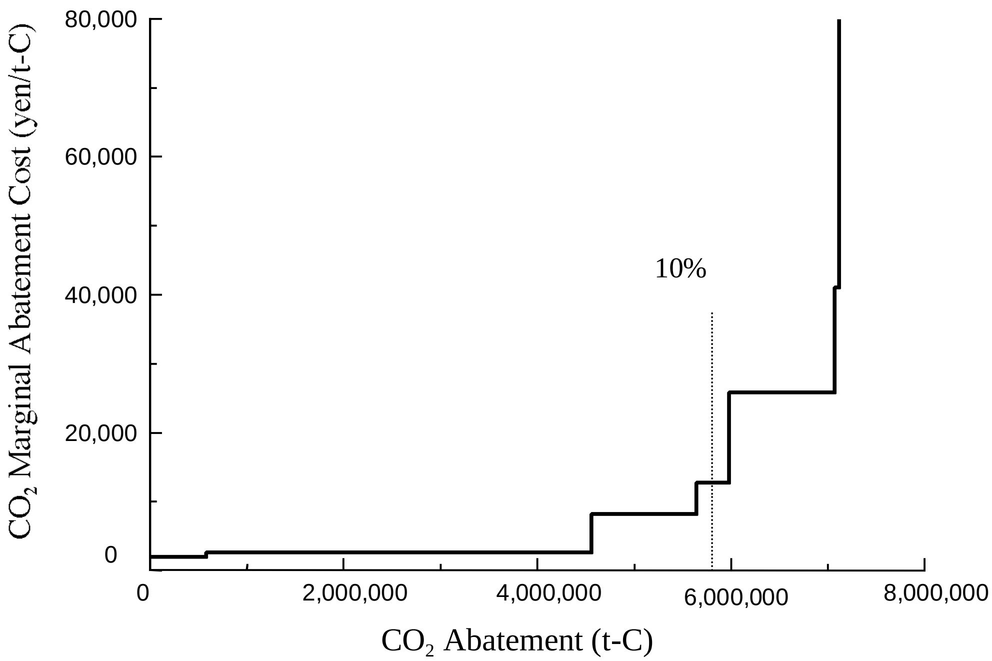

Figure 2.4 Aggregate Marginal Abatement Curve

The most remarkable feature of the aggregate marginal abatement cost schedule is the limited amount of abatement that is available. The total amount of abatement possible by re-dispatch within the four electric utility companies is 7.12 million tons of carbon, or 12.4% of 1997 CO_2 emissions, of which 4.56 million tons, or 7.9% of total emissions, is available at a cost of less than 5,000 yen/t-C. CO_2 emissions from Japanese electric utilities in 1997 were 5.4% higher than in 1990[4] so that if they were required to reduce emissions to a level 9% below 1990, a 15.8% reduction would be required.

The amount of abatement available through re-dispatch is limited in part because of the assumption we adopt that re-dispatch occurs only within each of the four electric utilities. This assumption rules out re-dispatching from utility D's coal-fired generation to unused nuclear capacity at utilities A and C. Relaxing this assumption to allow re-dispatch without regard to utility system would increase the amount of abatement available at less than 5,000 yen/t-C by about 30% to 5.91 million tons, or 10.3% of 1997 emissions, and total abatement to 10.47 million tons, or 18.2% of emissions. Even so, the amount of abatement available through re-dispatch is small and the cost of meeting the 9% below 1990 target would be high.

3. LOOKING FORWARD TEN YEARS

3.1 Introduction

Looking forward to some future date with continuing economic growth introduces increased generation and capacity additions. Since abatement by re-dispatch depends so much on the amount of unused low-emitting capacity, the amount of abatement available at the future date could be greater or less depending on the fuel characteristics of the added capacity and the predicted generation. Moreover, if the capacity additions are CO_2 emitting and construction has not yet started, changing plans to build lower emitting capacity additions will provide more abatement.

In this chapter, we start by looking at what is predicted for the year 2007 and evaluating abatement through re-dispatch without any change in predicted capacity additions. Then, having determined the abatement possibilities without any change in what we assume is a least-cost plan for capacity additions without consideration of carbon value, we analyze the abatement possibilities through conversion of planned high-emitting capacity additions to lower-emitting forms of generating electricity. Such conversions will also change the capacity configuration and amount of abatement by re-dispatch and these effects of conversion will also have to be considered.

3.2 Carbon Abatement Possibilities in Ten Years with Predicted Capacity and Generation

The first step is to determine the planned capacity additions and expected dispatch without any policy requirement to reduce CO_2 emissions. **Table 3.1** shows expected generating capacity by fuel for the same four utilities in 2007 as predicted by METI[7], and **Table 3.2** shows the differences from existing 1997 capacity. Most of the planned capacity additions are coal and LNG2, which account for 32% and 41% of the total, respectively.

Unfortunately, the METI forecast does not provide predicted fuel use by utility in 2007 but only for all utilities in Japan as a whole[6]. In the absence of utility specific data on fuel use, we take the utilization implicit in the fuel use and capacity forecasts for Japan as a whole to calculate average utilization by fuel and apply those factors to the corresponding fuel specific capacity of the four utilities. These utilization factors are 27% for oil, 61% for coal, 41% for both LNG options, and 76% for nuclear plants. As before, we assume that LNG2 plants are dispatched at 60% and assign the rest of the LNG consumption to LNG1. As a result, the LNG1 utilization factors for utilities A, B, and C are 27%, 23% and 33%, respectively. Application of these factors results in the generation given in **Table 3.3** and application of the appropriate emission factors (from Table 2.4) results in the CO_2 emissions given in **Table 3.4**.

In the aggregate, capacity is predicted to increase by 30%, generation by 20%, and emissions by 28%. These predictions imply that aggregate utilization will decline from 53% to 49% and that emission intensity will increase by 7% from 112.3 g-C/kWh to 119.9 g-C/kWh. The latter

Table 3.1 Predicted Generation Capacity in 2007 (MW^e) [7]

	A	B	C	D	Total
Oil	9,200	8,780	14,080	—	32,060
Coal	2,200	4,247	1,800	9,940	18,187
LNG1	17,789	7,741	6,702	—	32,232
LNG2	12,861	7,409	2,984	—	23,254
Nuclear	20,070	5,000	9,770	1,383	36,223
Total	62,120	33,177	35,336	11,323	141,956
Total for Japan *(excluding hydro, wind, & self-generation)*					229,080
Ratio of the modeled utilities to the total for Japan					62.0%

Table 3.2 Changes in Capacity from 1997 to 2007 (MW^e)

	A	B	C	D	Total
Oil	0	1,000	2,200	0	3,200
Coal	2,200	2,147	1,800	4,300	10,447
LNG1	0	0	0	0	0
LNG2	8,061	3,549	1,644	0	13,254
Nuclear	2,760	1,380	0	1,383	5,523
Total	13,021	8,076	5,644	5,683	32,424

Table 3.3 Predicted Generation in 2007 (MWh)

	A	B	C	D	Total
Oil	21,759,840	20,766,456	33,302,016	0	75,828,312
Coal	11,755,920	22,694,269	9,618,480	53,115,384	97,184,053
LNG1	42,074,543	15,596,567	19,374,142	0	77,045,251
LNG2	67,597,416	38,941,704	15,683,904	0	122,223,024
Nuclear	133,618,032	33,288,000	65,044,752	9,207,461	241,158,245
Total	276,805,751	131,286,996	143,023,294	62,322,845	613,438,885
Total for Japan *(excluding hydro)*					1,007,900,000
Ratio of the modeled utilities to total for Japan					60.9%

Table 3.4 Predicted CO_2 emissions in 2007 (t-C)

	A	B	C	D	Total
Oil	4,351,968	4,153,291	6,660,403	0	15,165,662
Coal	3,174,098	6,127,453	2,596,990	14,341,154	26,239,695
LNG1	7,489,269	2,776,189	3,448,597	0	13,714,055
LNG2	9,396,041	5,412,897	2,180,063	0	16,989,001
Nuclear	801,708	199,728	390,269	55,245	1,446,950
Total	25,213,084	18,669,558	15,276,322	14,396,399	73,555,363

occurs because of the projected greater reliance on coal-fired and LNG2 generation at the expense of low-emitting nuclear power. Whereas coal and LNG2 together constitute 16% of 1997 capacity and nuclear 28%, coal and LNG2 provide 73% of the incremental capacity additions predicted for 2007 and nuclear only 17%.

We assume that the cost and technical characteristics of the capacity additions planned for 2007 are the same as given in Table 2.6 for 1997 and that fuel costs will increase as predicted by METI. **Table 3.5** provides the METI predictions for fuel prices in yen per kilocalorie, as well as in US dollars per million Btu (@120 yen/US$) and the percentage changes from 1997. As shown in **Table 3.6**, the ordering of dispatch is as before with the change that nuclear has replaced coal as the cheapest to dispatch on a variable cost basis.

By applying the same method as in the previous chapter, the re-dispatch options and the corresponding marginal abatement cost are given in **Table 3.7**. Since utilities A and C are planning to build coal-fired capacity, these utilities will have all feasible options available in 2007, and utility D's plans to build nuclear capacity will give it the capability to re-dispatch some of its coal-fired generation.

Using data on existing capacity and utilization and the same assumptions given before, the potential switching ability and the room left for generation of each of the model utilities would be given in **Table 3.8**.

Table 3.5 Fuel Cost in 2007 [3], [5], [6]

Unit	Oil	Coal	LNG	Nuclear
yen/10^3 kcal	2.50	1.064	3.00	0.817
US$/mmBtu	5.25	2.23	6.30	1.72
% change from 1997	+56%	+18%	+67%	+2%

Table 3.6 Marginal Cost of Dispatch for the Fuel

Fuel	**Marginal Cost** (yen/kWh)
LNG1	6.447
Oil	5.377
LNG2	5.158
Coal	2.341
Nuclear	2.036

Table 3.7 Marginal Abatement Cost through Change in Dispatch (yen/t-C)

Dispatch Option	Utility A	Utility B	Utility C	Utility D
(1) Oil → LNG1	71,366	71,366	71,366	—
(2) Coal → Oil	50,516	50,516	50,516	—
(3) Coal → LNG1	50,067	50,067	50,067	—
(4) Coal → LNG2	25,319	25,319	25,319	—
(5) LNG1 → LNG2	12,821	12,821	12,821	—
(6) Oil → LNG2	8,197	8,197	8,197	—
(7) LNG2 → Nuclear	3,759	3,759	3,759	—
(8) LNG1 → Nuclear	2,907	2,907	2,907	—
(9) Oil → Nuclear	2,577	2,577	2,577	—
(10) Coal → Nuclear	1,894	1,894	1,894	1,894

Compared with the situation in 1997, the amount of electricity that could be generated from unused low-emitting capacity has greatly expanded from about 49 TWh to 105.5 TWh, while the amount of high-emitting generation available for re-dispatch has not increased so much from 150 TWh in 1997 to 179 TWh in 2007, although more of it is coal-fired than before. These circumstances should lead to more and cheaper abatement possibilities.

With no change in construction plans, the abatement possibilities and costs for utilities A to D are given in **Table 3.9** through **Table 3.12** and the combined marginal abatement possibilities are shown in **Table 3.13**. The aggregate marginal abatement cost schedule for 2007 is shown in **Figure 3.1**, along with that from 1997 for comparison.

Table 3.8 Switching ability through Change in Dispatch

Utility	A		B		C		D	
	change in utilization	*Gigawatt-hours*	*change in utilization*	*Gigawatt-hours*	*change in utilization*	*Gigawatt-hours*	*change in utilization*	*Gigawatt-hours*
Oil	–17%	–13,701	–17%	–13,075	–17%	–20,968	0%	0
Coal	–51%	–9,829	–51%	–18,974		–8,042	–51%	–44,408
LNG1	–17%	–26,491	–13%	–8,815	–23%	–13,503	0%	0
LNG2	30%	33,799	30%	19,471	30%	7,842	0%	0
Nuclear	14%	24,614	14%	6,132	14%	11,982	14%	1,696

Table 3.9 Utility A Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Coal → Nuclear	Coal (61%→10%)	Nuclear (76%→82%)	2,594,782	1,894
Oil → Nuclear	Oil (27%→10%)	Nuclear (82%→89%)	2,657,924	2,577
LNG1 → Nuclear	LNG1 (27%→26%)	Nuclear (89%→90%)	268,030	2,907
LNG1 → LNG2	LNG1 (26%→10%)	LNG2 (60%→82%)	972,389	12,821
		Total abatement	6,493,125	

Table 3.10 Utility B Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Coal → Nuclear	Coal (61%→44%)	Nuclear (76%→90%)	1,669,703	1,894
Oil → LNG2	Oil (27%→10%)	LNG2 (60%→80%)	797,586	8,197
LNG1 → LNG2	LNG1 (23%→14%)	LNG2 (80%→90%)	238,017	12,821
Coal → LNG1	Coal (44%→10%)	LNG1 (14%→33%)	1,163,732	50,067
		Total abatement	3,869,038	

Table 3.11 Utility C Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Coal → Nuclear	Coal (61%→10%)	Nuclear (76%→85%)	2,123,004	1,894
Oil → Nuclear	Oil (27%→24%)	Nuclear (85%→90%)	717,843	2,577
Oil → LNG2	Oil (24%→18%)	LNG2 (60%→88%)	451,427	8,197
LNG1 → LNG2	LNG1 (33%→32%)	LNG2 (88%→90%)	22,897	12,821
Oil → LNG1	Oil (18%→10%)	LNG1 (32%→49%)	217,080	71,366
		Total abatement	3,532,251	

Table 3.12 Utility D Marginal Abatement Cost

Dispatch Option	Capacity factor change		CO_2 Abatement (t-C)	Marginal Cost (yen/t-C)
Coal → Nuclear	Coal (61%→59%)	Nuclear (76%→90%)	459,753	1,894
		Total abatement	459,753	

Table 3.13 Aggregate Marginal Abatement Cost

Dispatch Option	**Marginal Cost** (yen/t-C)	**CO_2 Abatement** (t-C)
Coal → Nuclear	1,894	6,847,242
Oil → Nuclear	2,577	3,375,767
LNG1 → Nuclear	2,907	268,030
Oil → LNG2	8,197	1,249,013
LNG1 → LNG2	12,821	1,233,303
Coal → LNG1	50,067	1,163,732
Oil → LNG1	71,366	217,080
	Total Abatement	14,354,167

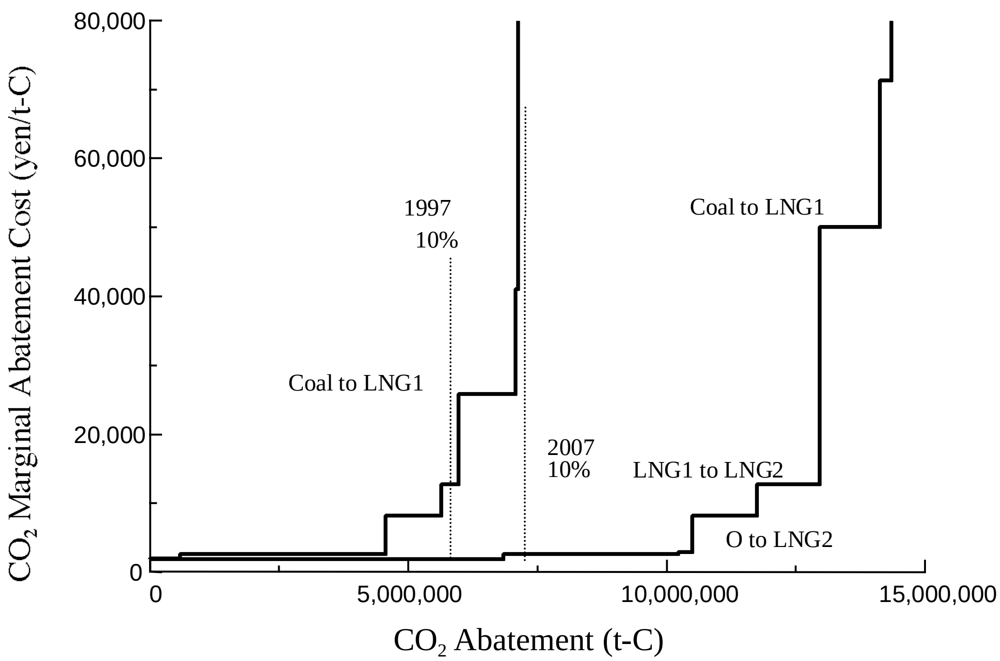

Figure 3.1 Aggregate Marginal Abatement Schedules, 1997 and 2007

The most obvious change between 1997 and 2007 is the significant expansion of the low cost re-dispatch possibilities. In 1997, only 4.5 million t-C could be abated at costs under 5,000 yen/t-C; in 2007, this capability has increased more than two-fold to 10.5 million t-C. The reasons are two. First, the amount of unused nuclear capacity is predicted to increase from 2.57 GW^e in 1997 to 5.07 GW^e in 2007, which reflects both the increase in nuclear capacity from 30.7 GW^e to 36.2 GW^e and a decrease in aggregate utilization from 82% to 76%. Second, the near doubling of high-emitting, coal-fired generation allows most of this unused nuclear capacity to be re-dispatched from coal-fired generation thereby providing the cheapest abatement possible. In 1997, the possibilities for switching from coal to nuclear were limited to utility B and only 13% of the unused nuclear capacity was used for this form of re-dispatch. In 2007, the same option accounts for 65% of the aggregate low-cost abatement possibilities.

The amount of abatement available through re-dispatch is predicted to be significantly greater in 2007 than what it is in 1997, but it is still not enough to meet the expected abatement from the electricity generating sector. An emissions target of 9% below 1990 levels implies emissions of 42.1 million tons of carbon in this simulation, or a 43% reduction from what emissions would be without any re-dispatch. The required abatement is so much greater because of the 20% increase in generation and the 7% increase in carbon intensity per kilowatt-hour of generation. As in 1997, the required abatement could not be achieved by re-dispatch; however, the relatively CO_2-intensive capacity additions could be converted to low-emitting capacity at some cost. We turn now to that question.

3.3 CO_2 Reduction by Converting Planned Capacity Additions

Japanese electric utility plans call for additions of nuclear, LNG combined cycle, coal, and oil capacity. The first three can be considered base load capacity for all have capacity factors of 60% or above, while the added oil capacity is for peaking and cycling use. Nuclear capacity additions would not be reconsidered on account of a carbon emission reduction policy, but fossil-fuel-fired ones would be. **Table 3.14** presents the calculation of the direct cost of substituting lower emitting capacity for planned coal, LNG2, and oil capacity additions. In making these calculations, we assume a kW^e for kW^e capacity replacement so that the predicted aggregate relation of capacity, generation, and reserve margin is preserved. As a result, nuclear capacity added as the result of a conversion would be dispatched at the same utilization factor as the planned unit it replaces, for instance 61% when a coal unit is converted, not the 76% utilization factor applying to other nuclear capacity. Four conversion options exist: one for cycling uses, from oil to LNG1, shown in the bottom right-hand quadrant of Table 3.14, and three base load options—coal to nuclear, coal to LNG2, and LNG2 to nuclear—shown in the remaining three quadrants.

Converting planned oil peaking capacity to simple cycle LNG1 would be very expensive, essentially because very little reduction in CO_2 emissions per unit of re-dispatch occurs (22 g-C/kWh). Accordingly, we do not consider it further. Surprisingly, all three base load conversion alternatives incur a direct cost of about 10,000 yen/t-C, which compares favorably with the cost of re-dispatching from LNG1 to LNG2, which would be required without conversions if more than 13 million tons of carbon, or about 18% of predicted 2007 emissions, were to be abated. Perhaps the most surprising feature of Table 3.14 is that LNG2 offers no advantage as the type of generation to which planned coal capacity additions would be converted. Converting a planned coal unit to LNG2 costs half as much as converting it to nuclear (1.43 yen/kWh vs. 2.72 yen/kWh), but CO_2 emission reduction per kilowatt-hour is also half as much (131 g-C/kWh vs. 264 g-C/kWh). Moreover, as a candidate for converting planned capacity additions to nuclear, LNG2 is as attractive as coal. This conversion alternative would abate only half as many emissions per converted kWh, but the cost is also half as much.

Table 3.14 Direct Cost of Converting Planned Capacity Additions

	New Coal	New Nuclear	Difference	New Coal	New LNG2	Difference
Construction Cost	304,000	377,000	73,000	304,000	232,000	–72,000
Utilization Factor	61%	61%		61%	61%	
Fixed Cost (yen/kWh)	7.57	10.59	3.02	7.57	6.18	–1.39
Var. Cost (yen/kWh)	2.34	2.04	–0.31	2.34	5.16	2.82
Total Cost (yen/kWh)	9.91	12.63	2.72	9.91	11.34	1.43
CO_2 factor (g-C/kWh)	270	6	264	270	139	131
CO_2 Cost (yen/t-C)			10,297			10,906
	New LNG2	**New Nuclear**	**Difference**	**New Oil**	**New LNG1**	**Difference**
Construction Cost	232,000	377,000	145,000	206,000	214,000	8,000
Utilization Factor	60%	60%		27%	27%	
Fixed Cost (yen/kWh)	6.28	10.77	4.49	11.56	12.88	1.32
Var. Cost (yen/kWh)	5.16	2.04	–3.12	5.38	6.45	1.07
Total Cost (yen/kWh)	11.44	12.80	1.36	16.94	19.32	2.39
CO_2 factor (g-C/kWh)	139	6	133	200	178	22
CO_2 Cost (yen/t-C)			10,249			108,520

The cost of building new lower emitting capacity to replace existing high-emitting capacity can also be calculated from Table 3.14. For instance, new nuclear capacity at 61% utilization would cost 12.63 yen/kWh and, if it were to replace existing coal capacity, the only off-setting savings would be the variable costs of 2.34 yen/kWh associated with running the replaced coal unit. The net cost would be 10.29 yen/kWh and, for each kWh converted, 264 grams of carbon would be reduced. The cost per ton works out to about 38,900 yen/t-C, almost four times the cost of replacing the same high-emitting capacity before the fixed costs are sunk. Other alternatives, such as replacing existing coal plant with new LNG2 or existing LNG2 with new nuclear, are even more costly. This comparison shows, not surprisingly, that converting planned capacity additions, before the fixed costs are sunk, is far cheaper than replacing existing capacity. Accordingly, we do not further consider the building of new low-emitting capacity to replace existing high-emitting capacity.

Table 3.14 provides the per ton cost of the carbon abated due to the direct effects of converting the planned capacity additions; however, changing the fuel characteristics of planned capacity additions also alters the amount of abatement available through re-dispatching in 2007 and these indirect effects should be taken into account. In particular, converting planned coal capacity additions will remove some abatement from the lowest-cost segment in Figure 3.1, although the nuclear capacity thereby freed up will still be used for re-dispatching from some other high emitting generation. Also, when the conversion is to nuclear, the added unused capacity provides further low-cost abatement opportunities. More generally, any conversion potentially involves two indirect effects that we call the substitution and capacity effects. The substitution effect refers to the substitute uses of any unused low-emission capacity that is freed up by the conversion, which is the case when the conversion is away from coal. If the utility has pre-existing coal capacity and generation, such as B and D in our simulation, then the freed-up low-emission capacity will still be used to abate emissions from coal-fired generation and the substitution effect will be zero. However, if there is no pre-existing coal capacity or generation, as is the case for A and C, the freed-up low-emission capacity will be used to abate emissions from oil or LNG1 generation and the net substitution effect will be negative. The capacity effect refers to the additional abatement that occurs as the result of adding more unused low-emitting capacity to the system. Conversions to nuclear capacity always provide more low-cost abatement opportunities through re-dispatch and this effect will always be positive for conversions to nuclear. In contrast, conversions to LNG2 do not add unused capacity offering cheap abatement so that this indirect effect is zero.

Table 3.15 shows the extent of the indirect effects and their impact on cost per 100 MW^e of converted capacity for the four utilities. Since fuel choices and capacity utilization among utilities vary, the indirect effects will be different. For all utilities, we calculate the indirect effects on the assumption that each utility converts all of its planned base load capacity additions to lower emitting capacity, either nuclear or LNG2 in the case of coal capacity additions or to nuclear in the case of LNG2 capacity additions. Abatement factors (g-C/kWh) and cost (yen/t-C) are also given for reference.

Each of the three panels illustrates one of the three base load conversion options. Within each panel, the direct effect from Table 3.14 is given in the first row, and the rows above the box indicate the indirect effects. These indirect effects include the two just described and a residual other effects.

Consider the first conversion option, coal to nuclear, as an example. Given the uniform utilization assumption of 61%, the direct abatement effect (141,071 tons of carbon per 100 MW^e converted) is the same for all four utilities. The next four rows indicate the indirect substitution effects. For this conversion option, 117,945 t-C less would be abated in 2007 in the coal to nuclear segment, which costs 1,894 yen/t-C. This amount is less than the direct effect because of the 10% minimum utilization we assume for any capacity that is in place. The freed-up nuclear capacity will be used for other forms of abatement by re-dispatch, which for utilities B and C will be generation from pre-existing coal capacity and the substitution effect for these two utilities will be zero. In contrast, utilities A and C do not have any pre-existing coal generation so that the nuclear capacity freed-up by the conversion will be used to re-dispatch oil-fired generation for utility C and LNG1 generation for utility A. In both of these cases, the substitution effect is negative.

The capacity effect is shown in the three shaded lines and it is always positive for any conversion to nuclear power since there is always higher emissions generation that can be abated at lower cost by re-dispatching to any unused nuclear capacity. The amount of abatement will depend, however, on the type of generation that will be re-dispatched. The extra capacity creates the most abatement for utility D because all of the additional unused nuclear capacity is used to re-dispatch coal-fired generation. The capacity effect is less for utility B because the amount of additional unused nuclear capacity is more than enough to re-dispatch all of its remaining coal-fired generation (down to the 10% minimum) and some of that new unused capacity serves to re-dispatch oil-fired generation. For utilities C and A, the additional nuclear capacity is used to re-dispatch oil and LNG1, respectively, in each case with less abatement and at slightly higher cost.

In some instances, a third indirect effect can occur as a result of the cascading displacement of abatement segments by the substitution and capacity effects. For instance, in the first panel, the conversion of utility C’s planned coal capacity additions frees up and adds enough nuclear capacity that there is less need to call upon unused LNG2 capacity to re-dispatch all the oil-fired

Table 3.15 Conversion Options: Abatement and Cost

New Coal to New Nuclear	**Abat Fact**	**Cost**	**A**	**B**	**C**	**D**
Direct Effect	0.264	10,297	141,071	141,071	141,071	**141,071**
Less Baseline C to N Abatement	0.264	1,894	-117,945	-117,945	-117,945	**-117,945**
Substitute C to N Abatement	0.264	1,894		117,945		**117,945**
Substitute O to N Abatement	0.194	2,577			86,671	
Substitute LNG1 to N Abatement	0.172	2,907	76,843			
Extra Capacity: C to NewN	0.264	1,894		55,419		**67,067**
Extra Capacity: O to NewN	0.194	2,577		8,559	49,284	
Extra Capacity: LNG1 to NewN	0.172	2,907	43,695			
Other: O to LNG2	0.061	8,197			-11,528	
Total Indirect			2,593	63,978	6,482	**67,067**
Total Abatement			143,664	205,049	147,553	**208,138**
Weighted Cost			10,995	7,704	8,551	**7,589**
New Coal to New LNG2	**Abat Fact**	**Cost**	**A**	**B**	**C**	**D**
Direct Effect	0.131	10,906	70,001	70,001	70,001	70,001
Less Baseline C to N Abatement	0.264	1,894	-117,945	-117,945	-117,945	-117,945
Substitute C to N Abatement	0.264	1,894		117,945		117,945
Substitute O to N Abatement	0.194	2,577			86,671	
Substitute LNG1 to N Abatement	0.172	2,907	76,843			
Extra Capacity: C to NewLNG2	0.131	25,319				
Extra Capacity: O to NewLNG2	0.061	8,197				
Extra Capacity: LNG1 to NewLNG2	0.039	12,821				
Other: O to LNG2	0.061	8,197			30,337	
Other: LNG1 to LNG2	0.039	12,821	-17,404		7,502	
Total Indirect			-41,102	0	-937	0
Total Abatement			28,899	70,001	69,064	70,001
Weighted Cost			47,000	10,906	14,474	10,906
New LNG2 to New Nuclear	**Abat Fact**	**Cost**	**A**	**B**	**C**	**D**
Direct Effect	0.133	10,906	**69,905**	**69,905**	**69,905**	NA
Less Baseline LNG2 to N Abatement	0.133	3,759	**0**	**0**	**0**	NA
Substitute Abatement: None						
Extra Capacity: C to NewN	0.264	1,894		**69,379**		NA
Extra Capacity: O to NewN	0.194	2,577				NA
Extra Capacity: LNG1 to NewN	0.172	2,907	**45,202**		**50,983**	NA
Other: None						
Total Indirect			**45,202**	**69,379**	**50,983**	NA
Total Abatement			**115,107**	**139,284**	**120,888**	NA
Weighted Cost			**7,366**	**6,087**	**7,013**	NA

generation. The abatement provided by the extra nuclear capacity provides 49,284 tons of additional abatement, of which 11,528 tons is abated at a cost of 2,577 yen/t-C (oil to nuclear) instead of 8,197 yen/t-C (oil to LNG2).

The first row in the boxed area sums the abatement from all the indirect effects and the second row gives the total abatement taking indirect effects into account. When planned coal capacity additions are converted to nuclear, the two utilities with pre-existing coal generation add about half again as much abatement through indirect effects, while the two utilities without pre-existing coal generation add relatively little indirect abatement. For the two utilities with pre-existing coal generation, the freed-up and extra nuclear generation provided by the conversion is put to use abating coal-fired generation that would otherwise either not be abated or be abated at higher cost. For the other two utilities, the freed-up and extra nuclear capacity also provides additional low-cost abatement but it abates oil or LNG1 generation. In sum, less is abated per kilowatt-hour re-dispatched and at slightly higher cost. The third row in the boxed area provides the weighted average cost when the indirect effects are included with the direct effects. The simplest case is utility D. Converting its planned coal capacity additions to nuclear provides 141,071 t-C abatement at 10,297 yen/t-C and 67,067 t-C at 1,894 yen/t-C for an average cost per ton of 7,589 yen/t-C for this conversion.

Including indirect effects usually reduces the cost of the conversion, but this is not always the case. For instance, the weighted average cost is higher than the direct cost for utility A, even though the indirect effects add 2,593 t-C per 100 MW^e converted. When all the indirect effects are included, the conversion removes 117,945 t-C of abatement at 1,894 yen/t-C and adds 120,538 t-C of abatement at 2,907 yen/t-C. Stated differently, 117,945 t-C of abatement cost 1,013 yen/t-C *more* than would be the case without the conversion and an additional 2,593 t-C are provided at a cost of 2,907 yen/t-C. In the end, the additional 2,593 t-C obtained through the indirect effects cost 48,984 yen per ton, which when weighted and averaged with the direct effect gives an overall cost of 10,995 yen/t-C for utility A when it converts planned coal capacity additions to nuclear.

The least-cost conversion alternative for each utility is indicated by the bold-face type. Surprisingly, that option is converting LNG2 to nuclear, not converting coal to either nuclear or LNG2. The new LNG2 to new Nuclear option has the advantage first of not incurring any substitution effects, since the planned LNG2 generation to be converted would not otherwise be dispatched in 2007, and second of making additional unused nuclear capacity available for re-dispatch. In contrast, the coal to LNG2 conversion is the least attractive option because it never brings capacity effects and the substitution effects are always non-positive. The coal to nuclear conversion is more attractive, even though it has the same substitution effects, because the capacity effects are significant, but less than for the LNG2 to nuclear option.

Several more general points need to be made concerning these conversion options. First, the indirect effects to be considered in calculating the cost of converting capacity additions include only the infra-marginal effects, those that are cheaper than the weighted average cost of the conversion. For instance, when utility A converts LNG2 capacity additions to nuclear at a direct cost of 10,249 yen/t-C, LNG1 generation that would otherwise have been re-dispatched to unused LNG2 capacity at 12,821 yen/t-C can now be re-dispatched to unused nuclear capacity at 2,907 yen/t-C. The amount of abatement provided by the LNG1 to LNG2 option is much less as a result, but that is relevant only if the utility is willing to incur abatement costs exceeding the direct cost of the conversion option. Thus, the weighted average cost of the conversion options in Table 3.15 includes only changes in the infra-marginal segments of the marginal abatement schedule, not changes that would be still more expensive than the weighted average cost of the conversion.

The change in the infra-marginal segments creates a minor problem in drawing the marginal abatement cost schedules whenever a utility converts planned capacity additions. We resolve this problem by keeping the pre-conversion segments unchanged and defining a conversion segment to include the direct effects and only the infra-marginal indirect effects. For instance, when utility B converts planned LNG2 capacity additions to nuclear, we do not add the 2.46 million tons of abatement obtained by indirect effects to the coal to nuclear segment at 1,894 yen/t-C and draw another line for 2.48 million tons at 10,906 yen/t-C representing the direct effects. Instead, one segment of 4.94 million tons at 6,087 yen/t-C is drawn. This convention preserves the shape of the marginal abatement cost schedule for obtaining any given level of abatement and no more.

Finally, utilities A, B, and C can obtain additional abatement, after the LNG2 capacity additions have been converted, by converting planned coal capacity additions, in what we call second stage conversions. The cost and quantity aspects of second stage conversions are calculated by comparing the total cost and quantity when both planned coal and LNG2 capacity are converted to nuclear with the total cost and quantity when only LNG2 is converted to nuclear, always taking indirect effects into account. Dividing the difference in total cost by the difference in abatement yields the average incremental cost for the second stage in this two-step process. By the definition of the two stages, the second stage will always be more costly than first stage conversions and that cost will depend mostly upon the ability to utilize the additional unused nuclear capacity that is made available. Utility A provides an example of a very expensive second stage conversion. Because of its heavy reliance on nuclear generation and the large amount of planned LNG2 capacity additions, this utility has re-dispatched all of its high-emitting generation and has no further need of unused nuclear capacity. Substitution effects still occur and in the end only 3% more abatement is provided by converting planned coal and LNG2 capacity additions than by converting only the LNG2 capacity additions. The cost of this further increment is very high: 67,365 yen/t-C.

In contrast, utilities B and C, could abate more by re-dispatch if they had more unused nuclear capacity and this circumstance reduces stage two conversion cost considerably. In the case of utility B, the second stage conversion adds 60% more abatement than the first stage alone at an incremental cost of 9,515 yen/t-C; and for utility C, 120% more abatement is provided at an incremental cost of 10,272 yen/t-C.

Figure 3.2 provides the aggregate abatement schedule for these four utilities including first and second stage conversions when the latter provide abatement at less than 20,000 yen/t-C. In this figure, the vertical lines indicate the percentage of estimated 2007 counterfactual emissions without any re-dispatch. Segments with the letter A, B, C, and D indicate abatement from conversions from the respective utilities. The first occurrence denotes the first stage conversion and the second occurrence for utilities A, B, and C denotes the second stage.

Figure 3.2 shows that converting planned fossil-fired capacity addition to nuclear capacity greatly expands the amount of abatement available in 2007. Without conversions, no more than 13 million tons of carbon, or 18%, of the 73 million t-C that would otherwise be emitted in 2007 could be abated through re-dispatch at costs of less than 20,000 yen/t-C. With conversions and re-dispatch of the new capacity configuration, 42 million t-C, or about 57% of the 73 million t-C counterfactual can be abated at costs of slightly more than 10,000yen/t-C or less. Slightly more than two-thirds of this abatement comes from converted, high-emitting capacity that, if built, could not be re-dispatched because of the otherwise limited amount of unused low-emitting capacity.

The preceding discussion should make clear that converting to nuclear power is what provides the ample abatement at costs ranging from 6,000 yen/t-C to slightly over 10,000 yen/t-C shown on Figure 3.2. If converting to nuclear power is not an option, then the amount of abatement available from the utility sector and its cost are very different.

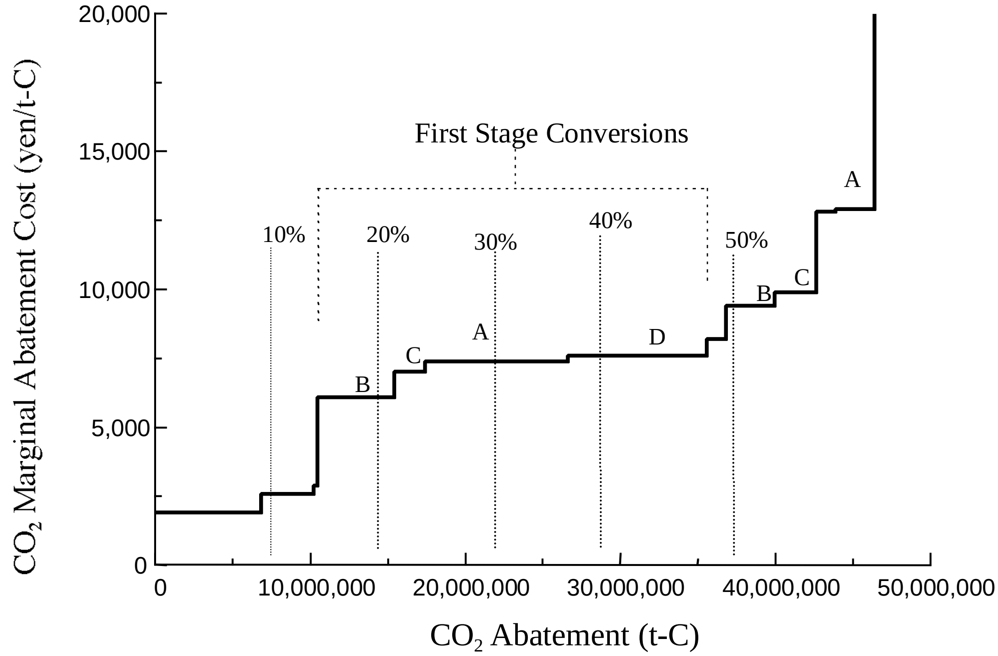

Figure 3.2 Aggregate Marginal Abatement Cost Schedule

Figure 3.3 shows the marginal abatement cost schedule if the only conversions feasible are from coal to LNG2. The cheapest conversions cost nearly 11,000 yen/t-C instead of 6,000 yen/t-C and the amount of abatement available at a cost of 10,000 to 11,000 yen/t-C or less has been reduced from almost 60% to a little over 20% of total emissions. Reaching the target of limiting

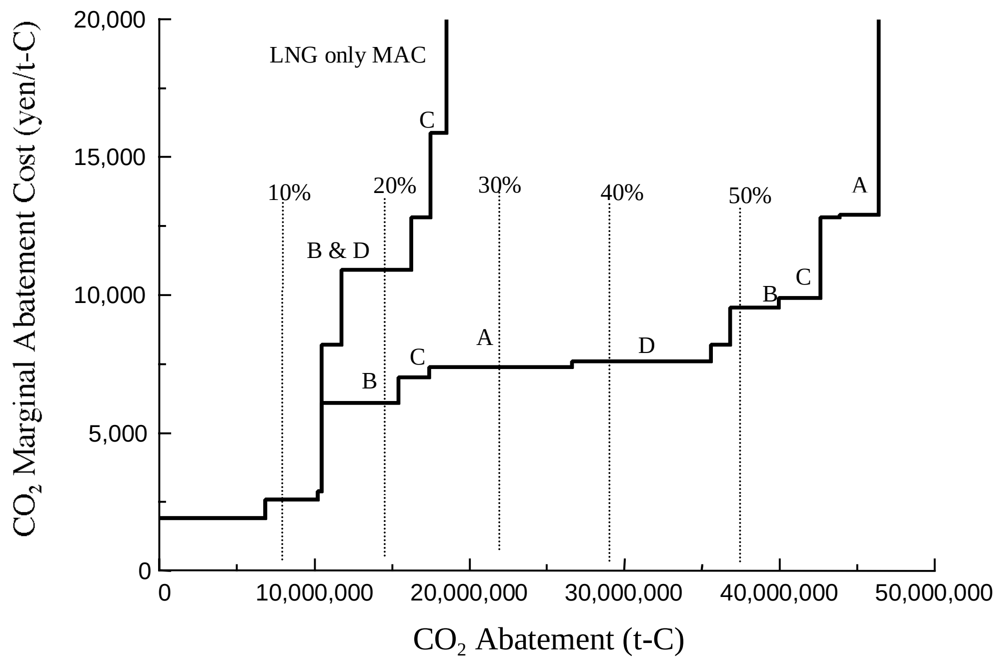

Figure 3.3 Aggregate Marginal Abatement Cost Schedule with & without Conversion to Nuclear Capacity

electric utility emissions to 9% below the 1990 level, which implies a 43% reduction from 2007 emissions, would be impossible.

3.4 The Effect of Different Utilization

Any utility making plans for abating CO_2 emissions in some future year will face two large uncertainties: future demand and fuel prices. Capital costs and the performance characteristics of planned capacity additions are known now or will not be subject to great variation when the new units are on line; and, assuming construction is not delayed, capacity can be determined by the investment decisions currently made. In contrast, and despite best estimates, actual demand and fuel prices in 2007 will surely vary from the expectation when decisions to add capacity are made. Accordingly, we examine how these variations affect the marginal abatement cost schedule. This section addresses variations in demand and the next one considers variations in the prices of coal and LNG, both of which are determined in a market external to Japan.

Figure 3.4 shows the effect of variations in demand that are ± 5% and ± 10% of the base case, which is represented by the bold line. Such variation is equivalent to a half and full percentage point variation in annual growth in demand over the decade. In the base case, demand is predicted to grow at 1.8% per annum so that the ± 10% cases represent demand actually growing at 2.8% or 0.7% per annum. These outer cases will come close to spanning the probability distribution for the variation in demand for any given construction plan, that is, before the variation would lead to either more or less capacity additions. In all cases, we assume that the increase or reduction in demand is spread proportionately among all generating units. Thus, if demand is reduced 5%, the generation from coal units will be 5% less, that from nuclear units also 5% less, etc.

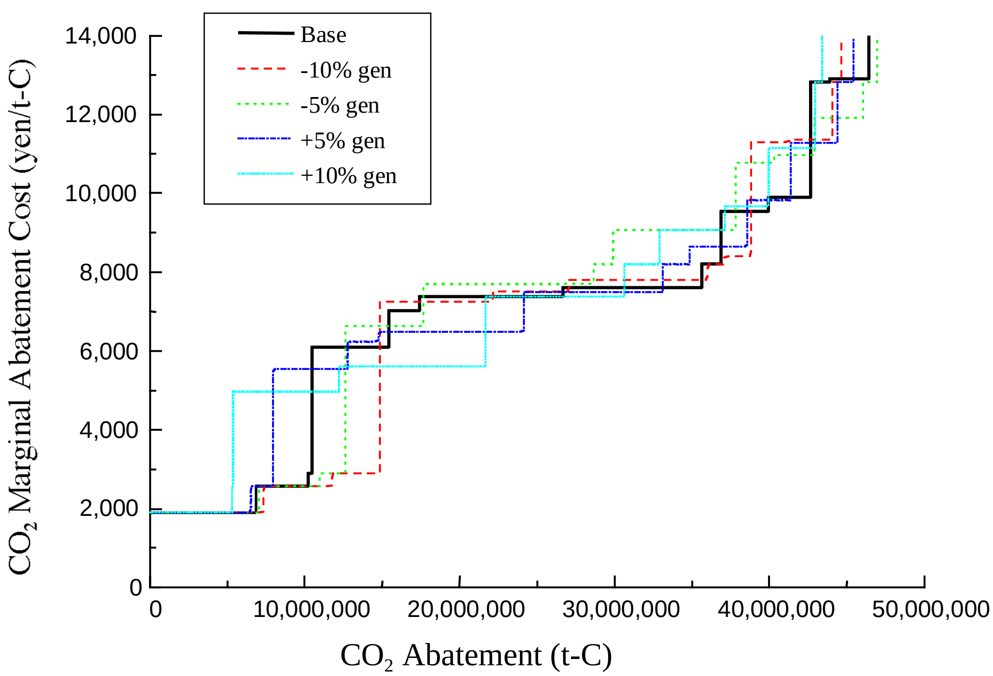

Figure 3.4 Marginal Abatement Cost Schedule with Variation in Utilization

Two effects of the variation in utilization are readily evident. First, the amount of abatement available at low cost (< 5,000 yen/t-C) is greatly affected. If demand is 10% less than expected, the amount of low-cost abatement increases by almost five million tons, or 50%; and 10% higher demand reduces such abatement by equal amounts. Second, the amount of abatement available after converting all planned coal and LNG2 capacity additions is not greatly affected by variations in demand. Depending on the case, the amount of abatement available at less than 13,000 yen/t-C ranges from 43.5 million t-C to 47.0 million t-C, a variation of about 7.5% for a 20% variation in generation.

The effect of variations in demand on the amount of abatement available at low cost is easily understood. Greater than expected demand implies less unused nuclear capacity and less re-dispatch to this very low-emitting and relatively low cost form of generation. In contrast, lower than expected demand makes more unused capacity available and increases the amount of low-cost abatement available through re-dispatch. These effects would be even greater if variations in demand were to fall disproportionately on the nuclear capacity providing low-cost abatement opportunities.

The variation in the percentage of emissions that can be abated is even greater than the variation in absolute amount, since emissions vary directly with demand. In the base case, the percentage of emissions that can be abated at low cost is 14.3%, but it increases to 18.1% and 22.4% in the –5% and –10% cases and it decreases to 10.3% and 6.6% in the +5% and +10% cases. This percentage variation emphasizes once again that the quantity of abatement available at low cost depends primarily on the availability of unused nuclear capacity. More generally, utility systems with little unused nuclear capacity will have very few opportunities to abate emissions at low cost through re-dispatching, and vice versa for systems with ample unused nuclear capacity, provided these latter systems also have fossil-fuel-fired generation to re-dispatch.

The relative constancy in the absolute amount of abatement available at higher cost (say up to 13,000 yen/t-C) may appear puzzling, but it reflects two offsetting influences. As just noted, higher (lower) than expected utilization implies less (more) abatement in the low-cost, pre-conversion segments of the MAC schedule. But, in compensation, higher (lower) than expected utilization implies more (less) abatement in the conversion segments of the MAC schedule. With higher than expected utilization, the pre-conversion segments are shortened and the conversion segments are lengthened, and conversely with lower than expected utilization. The indirect effects associated with conversion also play a role, but it is a minor one. In the end, the two influences approximately balance out and the absolute amount of abatement available at a cost of less than 13,000 yen/t-C varies relatively little with higher or lower than expected utilization.

Variations in utilization have a greater effect on the cost of the conversion segments. As can be seen on Figure 3.4, the general tendency, especially in the first stage conversions, is for higher utilization to reduce the cost of conversion and for lower utilization to increase that cost. This inverse relationship between utilization and incremental cost mainly reflects the effect of utilization on the direct cost of the conversion, as shown in **Table 3.16**. Conversion from a less capital-intensive to a more capital-intensive form of generation causes abatement cost to decline as utilization increases, while converting from a less to a more capital-intensive form of generation, such as from coal to LNG2, becomes more costly as utilization increases. The explanation lies in the share of capital costs in total costs. The greater the share of fixed cost, the greater the effect of variations in utilization on generation cost as the fixed cost is spread over more (or fewer) units of output. Thus, greater than expected utilization will make converting to nuclear more attractive and converting to LNG2 less attractive, and vice versa.

Table 3.16 Variation of Direct Conversion Cost with Utilization (yen/t-C)

Utilization Factor	Coal to Nuclear	Coal to LNG2	LNG2 to Nuclear
40%	16,309	5,343	27,111
45%	14,369	7,138	21,491
50%	12,816	8,575	16,994
55%	11,546	9,750	13,315
60%	10,448	10,730	10,249
65%	9,592	11,558	7,655
70%	8,824	12,269	5,432
75%	8,159	12,884	3,505
80%	7,577	13,423	1,819

Comparison across the rows of Table 3.16 shows that higher than expected utilization would not change first stage choices; converting LNG2 to nuclear becomes even more compelling. The table does suggest, however, that the coal to LNG2 conversion might become the first stage choice at lower than expected utilization. In fact, this does not occur because of the indirect conversion effects, which always work to make this conversion option the least attractive one, even if it may be relatively more attractive than before. The radar diagrams in **Figure 3.5** illustrate the relationship among the first stage conversion choices for the four utilities with all indirect effects included.

Each heavy line is a conversion option and the cheapest is the one closest to the center of the diagram. In all cases, the least attractive option on a weighted average cost basis, the outermost

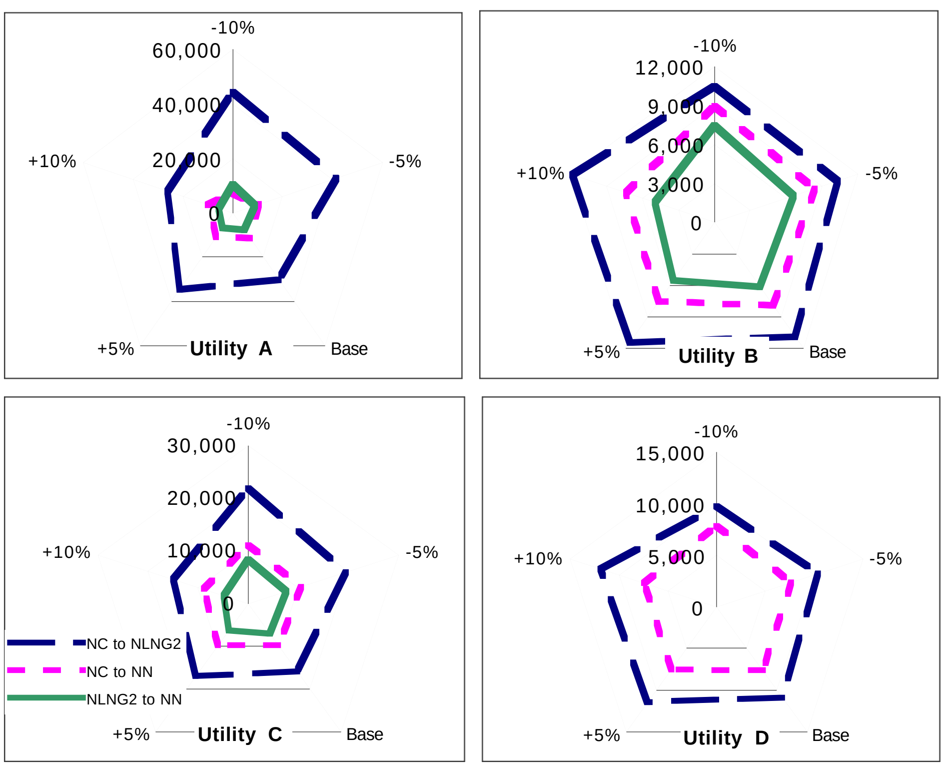

Figure 3.5 Effect of Utilization on Conversion Choices and Cost

line, is the coal to LNG2 conversion. The innermost line is the least costly alternative and except for one case (-10% for utility A) the LNG2 to nuclear conversion remains the most attractive choice. When utilization is greater than expected, the results are not surprising: the LNG2 to nuclear conversion becomes cheaper still and its advantage over the other alternatives becomes more compelling. When utilization is less than expected, the coal to LNG2 conversion can become more attractive, although not always, but it never approaches being competitive with the other alternatives for the reasons explained previously. Instead, the competition to the LNG2 to nuclear option for first stage conversion is coal to nuclear, and with less than expected demand, the conditions within the utility system may be such as to make this the preferred choice, as it is in this simulation for utility A with 10% less demand than expected.

Forecasts of future demand are never exactly accurate; however, the ability to defer (or to accelerate) commitments to planned capacity additions tends to keep capacity and generation aligned with each other. For instance, METI's current (2000) forecast for electricity demand in the year 2007 predicts 9% less generation than the 1997 forecast for 2007, about half the growth increment earlier expected; however, capacity additions are also predicted to be considerably less, 19.6 GW^e instead of 32.4 GW^e. Also, the composition of the predicted capacity additions is different. Only 1.4 GW^e of additional nuclear capacity is expected to be on line (instead of 5.5 GW^e) by 2007; the remaining capacity additions are LNG2 and coal.

3.5 Sensitivity to Different Fuel Prices

Since most of the generation and emissions originates with base load plants and the variable costs of coal and LNG generation are determined largely by prices in the world market, the prices of these two fuels are the most important ones for sensitivity analysis. Accordingly, **Figures 3.6** and **3.7** show the effect of varying the price of coal and LNG by ± 10% from the values assumed in the base case.

Unlike the case with unanticipated variations in demand, fluctuations in fuel prices do not affect either the cost or quantity of abatement in the low-cost, pre-conversion segments of the MAC schedule. The reason is that re-dispatch is going from a fossil-fueled unit to a nuclear unit, and the variable cost of nuclear generation is cheaper than all forms of fossil-fuel-fired generation. Consequently, the abatement cost of each option is determined by the cost involved in moving away from the previous least-cost dispatch order of the utility's generating system. In our simulation, which is our assumed value of epsilon (0.50 yen/kWh) divided by the amount of abatement achieved by each option.

As shown in Figure 3.6, variation in the price of coal has some effect, but not much, on the conversion segments. Such variation has no effect on the first stage LNG2 to nuclear conversions for utilities A, B and C; but it does affect the cost for utility D and the second stage conversions for the other utilities. In general, the effect of higher prices is to make abatement cheaper, since higher coal prices make coal-fired generation more expensive and thereby reduce the difference in generation cost between the coal capacity addition and the alternative. The opposite effects occur with lower coal prices.

In contrast, 10% variations in the price of LNG make a greater difference, not only in the cost of individual segments of the MAC schedule, but also in the ordering of those segments, as shown by Figure 3.7. First, the first stage LNG2 to nuclear conversions are affected in the

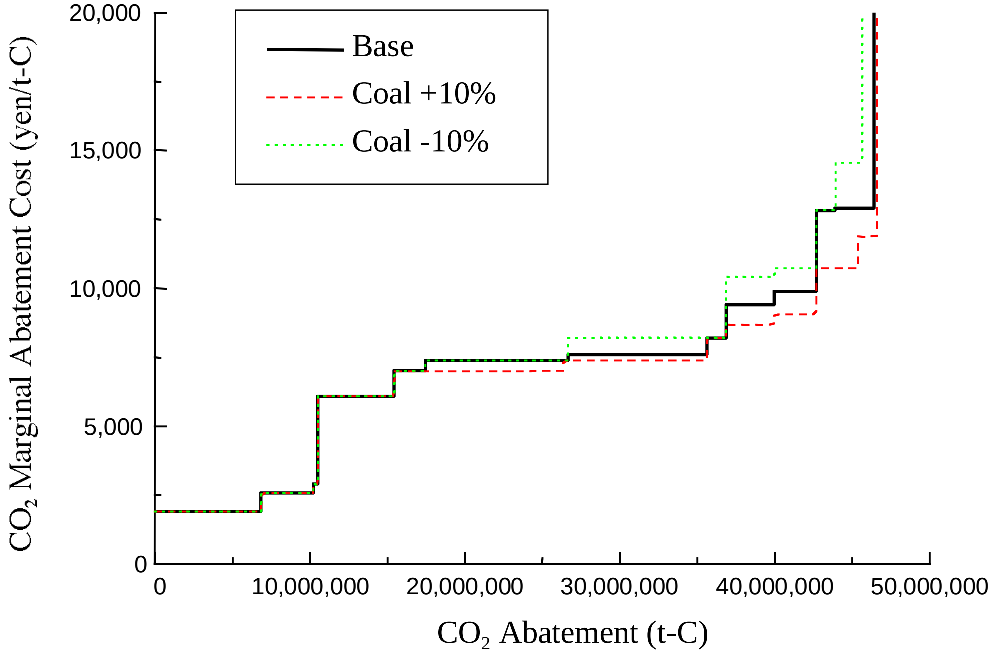

Figure 3.6 Marginal Abatement Cost Schedule with Variation in Coal Price

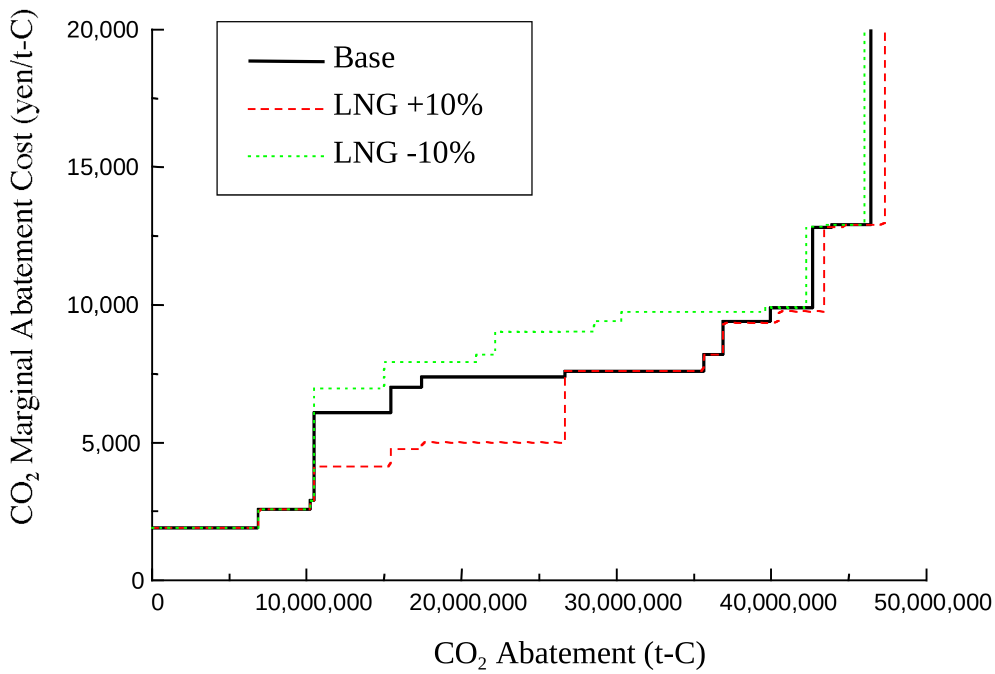

Figure 3.7 Marginal Abatement Cost Schedule with Variation in LNG Price

manner just described for coal to nuclear conversions: higher fuel prices reduce the cost of abatement and lower fuel prices raise it. The effect of a 10% variation in LNG price is greater than an equivalent variation in coal price because the share of the fuel price in total cost is greater for LNG2 than it is for coal or nuclear. Thus, 10% increases in LNG prices reduce the cost of the first stage conversions by about one-third. Comparable decreases in LNG prices have the opposite effect on these first stage conversions, while also making coal to LNG2 conversions more attractive, and at –10% sufficiently so that coal to LNG2 conversions are chosen for the first stage by utilities B and D. The incremental costs of these segments are higher through the range of abatement from 10 to 40 million t-C in the base case, but the order is now changed. At the high end, everything is converted to nuclear and the abatement schedules converge when all conceivable abatement opportunities have been exploited.

Finally, since predictions of fuel prices have been famously wrong, one might ask how accurate do the predictions for 2007, made in 1997, look in 2001 and how this perspective might change the results indicated here. **Table 3.17** compares first quarter 2001 fuel prices in Japan with those we have used for 1997 and as predicted in that year for 2007.

In a little over three years, oil and LNG prices have risen each by about 25%, or about half of the increase in nominal prices predicted for oil by 2007 and about 40% of the predicted increase for LNG. The more remarkable change has been in coal prices, which have declined by about a third over the same three years and stand now at a level about 60% of what was predicted for 2007. A variation of this magnitude is beyond that we tested above and it does have greater effect, generally shifting the MAC schedule inwards, as a result of re-dispatching now cheaper oil and LNG1 generation to unused nuclear capacity instead of coal generation, and upwards, as the result of the now more expensive conversions of coal to nuclear by utility D and by the other utilities in second stage conversions.

Table 3.17 Fuel Price Comparisons [5], [8]

	1997	1st Qtr, 2001	Predicted 2007
Oil (yen/kilolitre)	15,141	18,807	23,550
LNG (yen/ton)	23,358	29,228	39,038
Coal (yen/ton)	5,928	4,014	7,016

4. CONCLUDING OBSERVATIONS

The amount of unused nuclear capacity recurs throughout this analysis as the main feature determining the cost and quantity of CO_2 abatement available in the electric utility sector. Unused nuclear capacity to which higher-emitting fossil-fuel-fired generation of any type could be re-dispatched almost entirely determines the amount of low-cost abatement available, without consideration of changes in construction plans. And conversions of planned capacity additions are at least as important for making more unused nuclear capacity available for re-dispatch as they are for the emissions abated directly by the conversion. Nuclear power generation plays this role because it combines low operating costs with very low emissions, but for this reason the amount of low-cost CO_2 abatement available from the utility sector may not be as great as commonly assumed. Low operating costs imply high utilization on any electrical system that is dispatched by least-cost principles. Hence, unused capacity combining low emissions and low cost is not likely to be great.

In this paper, we have explored this issue using data that is broadly representative of conditions in Japan. Without any changes in the capital stock, whether as it was in 1997 or as it is predicted to be in 2007, electric utilities would not be able to abate CO_2 emissions as much as called for in studies of abatement potential in the electric utility sector at any cost, not to mention at low costs of 3,000 yen/t-C or less at which from 10% to 15% of emissions could be abated. Changing the capital stock significantly expands abatement opportunities to about 55% of emissions but at a marginal cost of about 10,000 yen/t-C. These changes take the form of converting planned higher-emitting capacity additions, whether coal or LNG combined cycle, to low-emitting nuclear capacity additions.

In this simulation and assuming that Japanese electric utilities would need to reduce emissions by about 43% as the targets in the Kyoto Protocol and the 1997 prediction of generation and emissions implies, the marginal cost would be about 7,500 yen/t-C, which is not extraordinarily high. More importantly, it assumes that planned fossil-fuel-fired capacity additions can be converted to nuclear. If that is not the case, and LNG combined cycles are the only means of reducing emissions through conversions, then the 43% abatement level cannot be reached and the cost of abating as little as 25% of existing emissions will be roughly twice what it would be if nuclear capacity additions were possible. These findings are not significantly altered by variations in utilization or in fuel prices, except when LNG prices are 10% or lower than what is forecast here. In that case, the marginal cost for abating 43% of emissions rises to about 9,300 yen/t-C because a lower LNG price makes LNG2 to nuclear conversions more expensive.

One of the most surprising results of this analysis is that LNG does not become the fuel of choice for replacing coal. LNG use is reduced along with that of coal and oil, especially in the conversion segments of the marginal abatement cost schedule. With no change in the capital stock, the cost of re-dispatching to unused LNG2 capacity is too high to attract any demand (while some LNG1 generation is re-dispatched to unused nuclear capacity) and in the first stage conversion segments, the least-cost choice is conversion from LNG2 to nuclear because of the indirect effects. That choice offers abatement of LNG2 emissions that would not otherwise be abated and brings in more unused nuclear capacity that can be used to abate other emissions, including emissions from pre-existing LNG2 capacity that could not otherwise be re-dispatched to lower emitting generating capacity.

The third implication of this analysis also has an element of paradox: utilities facing growing demand for electricity have more opportunities for abating emissions than utilities facing stagnant demand. Conversions of planned capacity additions provide most of the abatement potential from electric utilities. Without these capacity additions and their offsetting and yet-to-be-committed capital costs, the reasonably priced abatement potential is much less and, in this case, not enough to meet the target set for the electric utilities of reducing CO_2 emissions to 9% below the 1990 level.

As with any analysis, the conclusions reflect the data used and a number of simplifying assumptions, and these should be kept in mind. The data is broadly representative of capital cost and fuel price relations in the Japanese electric utility sector, and they would not be the same in other countries. In particular, the capital costs for all forms of generation are much higher than in the United States, for instance; and this will increase the importance of fuel price relations. Nevertheless, the more general features that dominate the analysis—the relative importance of fixed and variable costs in the various generating options, the abatement associated with changing from one form of generation to another, and the coincidence of low operating costs and low emissions—are characteristic of all countries.

A second and major limitation of our analysis is the extreme simplification of the network considerations that would inform and limit any decision to re-dispatch generation from one plant to another. We represent this limitation by a uniform cost charge of 0.50 yen/kWh, over and above differences in fuel costs, and assume that all generation of a given type (subject to the assumed 10% minimum utilization) can be re-dispatched to lower-emitting capacity once the combined fuel and network charge has been covered. Given the fuel price differences in this simulation, the level of this charge does not make much difference in the ordering or cost of various abatement segments, but we suspect that our assumption that all generation down to the minimum utilization level can be re-dispatched is generous.

A third limitation is our assumption that demand for electricity is unchanged as a result of the higher cost imposed by the carbon constraint. Although electricity demand is relatively inelastic, this assumption clearly understates the amount of abatement as increasing amounts of abatement are sought from the electric utility sector. This understatement offsets to an undetermined extent the likely overstatement of abatement opportunities due to our simplification of the network constraints.

This paper shows that the common perception that more low-cost abatement exists within the electric utility sector than its share of emissions would suggest carries with it an unspoken assumption that unused generating capacity combining low operating costs and low emissions is available or can be made so. In this context, that capacity is nuclear and without an ability to add that capacity, it is doubtful that the Japanese electric utility sector would be able to achieve the emission reductions implied by the Kyoto targets and this prediction of future demand. Re-dispatch or conversions to LNG seem unlikely to provide the expected low-cost abatement both because the abatement per re-dispatched kilowatt-hour is much less and the fuel cost of LNG is much higher than that of nuclear generation.

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