APPENDIX B

Stage One: Three Archetypal Approaches

Data Consolidation, Model Replication, and Evaluation

This appendix describes three representative or archetypal modelling approaches and their method of replication and final evaluation. Comparison of these approaches are documented in Chapter 4. These modelling approaches make use of techniques of scenario analysis, linear programming, mathematical decomposition, sensitivity analysis, risk analysis, and decision analysis. The main objectives of this stage of the two staged modelling experiment are 1) to determine the limitations of each approach, 2) to assess the potential for synthesis, and 3) to evaluate model completeness with respect to uncertainties.

The next section describes the data used in the capacity planning optimisation programme which is the core technique in the deterministic and probabilistic approaches. After this, the replication and evaluation of the three approaches are documented.

B.1 Data Consolidation

Accurate details of all power plants in the UK, especially the status of new plants, are highly confidential and proprietary. As a result, the task of data consolidation becomes one of reconciliating different and conflicting sources of published information. Before presenting the consolidated data of all plants in the NGC system, we discuss some problems with obtaining scarce data and reconciliating different sources of information. These problems present uncertainties in the data.

The main source of information for planning purposes is the annually published Seven Year Statement by the National Grid Company (NGC). This document is released in April each year and updated in July, October, and December. It contains the status of every plant by ownership and technology type in the NGC-operated transmission system as well as new plants that will be connected in the future. However, it does not give details of actual load factors, capital costs, fuel costs, thermal efficiencies, and emission factors. By the time it is released, some details may have changed. Therefore it is necessary to consult other sources, which are listed in table B.1. In case of conflict, the more reliable and recent publication is used.

Table B.1 Sources of Information

Code	Title of Publication
0	Offer report
1	Inside Energy 26-9-1991
1.1	Comments on LBS Model Inputs, Oct 92 (Southern Electric)
1.2	Inside Energy, 22-04-1993, vol 3 no. 21
2.1	NGC Report: 7 Year Statement, March 1992
2.2	NGC Update, Oct 1992
2.3	NGC Report: 7 Year Statement, April 1993
2.4	NGC Update, July 1993
3	National Power Press Release or Annual Report
3.1	National Power News, Aug 1992
3.2	National Power News, Sep/Oct 1992
3.3	National Power News, Dec 1992
3.4	National Power News, April/May 1993
4	PowerGen Press Release or Annual Report
4.1	The GEN (PowerGen newsletter)
5	Electric Power International, Mar 93
6	Newspaper articles (date given)
7	Hoare Govett: Independent Generation, Aug 1991
8	Energy World (monthly magazine of the Institute of Energy, UK)
9	International Coal Report, 2 Oct 1992
10	White Paper: The Prospects for Coal Conclusions of the Government's Coal Review, March 1993
11	Electricity Association: UK Electricity 1992
12	Power in Europe 23 Apr 1993, Issue No. 147 (ILEX UK Power Station Monitor)

Reported capacities vary widely, according to individual approximations of either registered or declared net capacities. Actual registered and declared net capacities may also change, making it difficult to monitor. Unless otherwise stated, registered capacities from NGC reports have been used.

There is some confusion over a unique name for a plant, which is usually the name of its location or owner. For new projects, sometimes no plant name is given, only the owner's name, but owners keep changing as different joint ventures or consortiums are formed. This is especially true of new plants which go through various name changes in the early stages of the project. For example, Greystones and Wilton, Teeside never appear together in the same source. So it can be assumed that they refer to the same plant, that of the largest CCGT. Obvious duplications have been eliminated where they correspond to different units of the same plant.

The life of a plant depends on a number of factors. Owners need only to give six months notice to the NGC for closure of plant, but permission to extend the life of a plant may enter into a time-consuming public inquiry. Because plant closure implies job losses, such announcements are not made in company newsletters unless the closures are 100% certain.

Uncertainties in commissioning of new plant are related to the stages in the process, as indicated by its status in table B.2. A company may sign a System Connection Agreement with the NGC before Section 36 Consent is given by the government. Transmission contracted plant (T) does not mean that it will go ahead. The best indicator of go-ahead is a combination of T, S, and U: Section 36 consent given (S) and Under construction (U) and Transmission contracted (T). In many cases, the announcement of new plant is merely a strategic move, signalling additional capacity. The major generators have employed this market signalling strategy to deter new entrants. Information on new plants in their early planning stages are difficult to obtain and verify.

Table B.2 Status of Plant

Code	Status Description
blank	not in NGC report and not sure of status
*	not directly connected to NGC
A	has applied for S36 planning permission, government consent under consideration
Ap	has applied for S36 planning permission, but pending results of public inquiry
D	decommission or closure of plant notice given
d	already decommissioned or in the decommissioning stage
E	existing plant in NGC reports/transmission system
I	has import facilities, e.g. to import coal, according to Kleinwort Benson Securities (1990) The Electricity Handbook
P	postponed or deferred
R	significant reduction in registered capacity
S	has Section 36 Consent
T	transmission contracted (agreement with NGC made)
U	under construction
X	transmission agreement with NGC cancelled (pertains to new plant)
Z	notified zero registered capacities for next 7 years (to 2000). The registered capacity shown here is the remaining capacity of the plant in the system.

The decommissioning years for all nuclear plant were taken from National Audit Office (1993) Costs of Decommissioning Nuclear Facilities, HMSO.

Plant data consolidated from various publications are presented in table B.3 and summarised in table B.4.

Table B.3 Existing Plant as at July 1993

SOURCE	STATUS	NAME	PLANT TYPE	CAPITAL COST £mio	DNC [11]	REGISTERED CAPACITY (MW)	OWNER*	COMMISSIONED	DECOMMISSIONING	Bid Price £/MWh
2.1,2.3	E	Dungeness B	AGR		720	*1,120*	NE	1985	2010	1.00
2.1,2.3	E	Hartlepool	AGR		1,020	*1,176*	NE	1989	2010	0.50
2.1,2.3	E	Heysham 1	AGR		1,020	*1,155*	NE	1989	2010	1.00
2.3	E	Heysham 2	AGR		1,230	*1,340*	NE	1989	2018	1.00
2.3	E	Hinkley Point B	AGR		1,120	1,248	NE	*1976*	2007	1.00
11		Maentwrog	Hydro		30		NE	1928		
1,1.1,2.3	E	Bradwell	magnox		245	248	NE	1962	1997	1.00
2.3	E	Dungeness A	magnox		424	450	NE	1965	1995	1.00
1,2.3	E	Hinkley Point A	magnox		470	470	NE	1965	1995	1.00
2.3	E	Oldbury	magnox		434	440	NE	*1967*	1998	1.00
2.3	E	Sizewell A	magnox		420	430	NE	1966	1996	1.00
2.2,2.3,2.4	ED	Trawsfynydd	magnox		390	240	NE	1965	1993	1.00
2.3	E	Wylfa	magnox		840	1,015	NE	1971	2001	1.00
		TOTAL ABOVE			**8,363**	**9,332**				
2.2,10,1.2, 2.3	E	Killingholme NP1	CCGT	250		620	NP	1993		14.10
11	E	Cwn Dyli	Hydro		10		NP	1989		
11	E	Dolgarrog	Hydro		27		NP	1924		
11		Mary Tavy Group	Hydro		3		NP	1932		
2.3	EI	Aberthaw B	large coal		1,401	1,455	NP	*1971*		15.25
2.3	E	Didcot	large coal		2,060	1,960	NP	*1972*		15.48
6 (26.5.93),2.3	EI	Drax	large coal		3,890	3,870	NP	*1974*		13.51
2.3	EI	Eggborough	large coal		1,971	1,940	NP	*1968*		14.09
2.3	E	Ironbridge B	large coal		984	970	NP	1970		13.74
2.3	E	Rugeley B	large coal		1,016	976	NP	1972		13.30
2.3	E	West Burton	large coal		1,988	1,932	NP	*1967*		13.89
2.3	ED	Blyth B	medium coal		620	626	NP	*1963*	1993	

Table B.3 continued

SOURCE	STATUS	NAME	PLANT TYPE	CAPITAL COST £mio	DNC [11]	REGISTERED CAPACITY (MW)	OWNER*	COMMISSIONED	DECOMMISSIONING	Bid Price £/MWh
2.3, 2.4	EID	Thorpe Marsh	medium coal		1,098	1,050	NP	*1963*	1994	13.48
2.3	EI	Tilbury B	medium coal		1,412	1,360	NP	*1968*		15.26
2.3	E	Willington B	medium coal		376	376	NP	*1962*		12.76
3, 3.2 D but 2.3 incl	ERIZ	Eggborough GT	OCGT, aux			68	NP	*1968*	1993	
6(9.4.93),2.3	E	Aberthaw B GT	OCGT, aux			51	NP	1967		93.81
0,2.3	E	Didcot GT	OCGT, aux			100	NP	*1972*		100.99
0,2.3	EZ	Drax GT	OCGT, aux			140	NP	*1974*		93.16
0,2.3	E	Fawley GT	OCGT, aux			68	NP	*1969*		94.30
0,2.3	E	Ironbridge GT	OCGT, aux			34	NP	1967		99.70
0,2.3	E	Littlebrook GT	OCGT, aux			105	NP	*1982*		93.01
0,2.3	E	Pembroke GT	OCGT, aux			75	NP	*1970*		95.76
0,2.3	E	Rugeley B GT	OCGT, aux			50	NP	1969		84.54
0,2.3, 2.4	EID	Thorpe Marsh GT	OCGT, aux			56	NP	1966	1994	79.78
0,2.3	E	Tilbury GT	OCGT, aux			68	NP	1965		130.82
0,2.3	EI	West Burton GT	OCGT, aux			80	NP	*1967*		94.14
0,11,2.3	E	Cowes GT	OCGT, main		140	140	NP	1982		93.03
0,2.3	E*	Letchworth GT	OCGT, main		140	140	NP	1979		93.16
0,2.3	E*	Norwich GT	OCGT, main		110	110	NP	1966		94.46
0,2.3	E*	Ocker Hill GT	OCGT, main		280	280	NP	1979		97.37
2.3	ERZ	Fawley	oil		1,034	968	NP	*1969*		40.76
6(9.4.93),2.3	E	Littlebrook D	oil		2,160	2,055	NP	*1982*		25.66
2.3	ERZ	Pembroke	oil		1,530	1,461	NP	*1970*		25.64
0, 2.2, 3.2,2.3	ERIZ	Aberthaw A	small coal		376	192	NP	*1960*	**1993**	18.07
2.3	E	Blyth A	small coal		448	456	NP	*1958*		14.25

Table B.3 continued

SOURCE	STATUS	NAME	PLANT TYPE	CAPITAL COST £mio	DNC [11]	REGISTERED CAPACITY (MW)	OWNER*	COMMISSIONED	DECOMMISSIONING	Bid Price £/MWh
0,2.2,3,9,2.3	E* Z	Rugeley A	small coal		560	228	NP	*1961*	**1993**	17.67
0,2.2,3,9,2.3	E R Z	Skelton Grange	small coal		448	228	NP	1961	**1993**	16.41
2.3	E*	Staythorpe B	small coal		336	354	NP	*1960*		15.59
2.2,2.3	E R Z	Uskmouth	small coal		336	228	NP	*1961*	**1993**	18.03
0,2.2,3,9,2.3	E R D Z	Willington A	small coal		392	98	NP	*1957*	**1993**	16.84
		TOTAL ABOVE			**25,146**	**24,968**				
3.4, 6(20.4.93), 8,1.2,2.3	E	Killingholme PG1	CCGT	300		900	PG	1992		14.10
4.1, 11		Rheidol	Hydro		49		PG	1966		
2.3	E	Cottam	large coal		1,970	1,988	PG	*1969*		14.38
6 (9.4.93),2.3	EI	Ferrybridge C	large coal		1,966	1,960	PG	*1966*		14.16
2.3	EI	Fiddler's Ferry	large coal		1,914	1,940	PG	*1971*		15.49
2.3	EI	Kingsnorth	large coal		1,954	1,940	PG	*1970*		
6 (26.5.93),2.3	E	Ratcliffe On Soar	large coal		1,974	1,990	PG	*1968*		14.27
2.3	E	Drakelow C	medium coal		910	999	PG	*1965*		15.29
2.3	E	High Marnham	medium coal		930	945	PG	*1959*		15.23
0 D but 2.3 incl	EI Z	Ferrybridge C GT	OCGT			34	PG	*1966*	1992	
0 D but 2.3 incl	EI Z	Fiddler's Ferry GT	OCGT			34	PG	*1969*	1992	
0, 4 D but 2.3 incl	EI Z	Kingsnorth GT	OCGT, aux			34	PG	1967	1992	
0 D but 2.3 incl	E Z	Ratcliffe GT	OCGT, aux			34	PG	*1968*	1992	
0,4 D, but 2.3 incl	E DI Z	Cottam GT	OCGT, aux			50	PG	*1969*	1992	
0,2.3	E	Grain GT	OCGT, aux			145	PG	*1979*		157.22
0,2.3	E	Ince GT	OCGT, aux			50	PG	1979		151.88

Table B.3 continued

SOURCE	STATUS	NAME	PLANT TYPE	CAPITAL COST £mio	DNC [11]	REGISTERED CAPACITY (MW)	OWNER*	COMMISSIONED	DECOMMISSIONING	Bid Price £/MWh
0,2.3	E*	Taylor's Lane GT	OCGT, main		140	132	PG	*1979*		152.00
0,2.3	E	Watford GT	OCGT, main		70	70	PG	*1979*		110.79
6(9.4.93),7,2.3	E	Grain	oil		2,068	2,700	PG	*1979*		39.52
2.3	E	Ince B	oil		1,010	960	PG	1982		34.84
2.3	E	Richborough	oil		342	342	PG	*1962*		21.01
0, 2,4, 9,2.3	E R	Castle Donington	small coal		564	210	PG	*1956*		22.58
		TOTAL ABOVE			**15,861**	**17,457**				
3.1,1.2,2.3	E*	Brigg	CCGT	100		272	IN	1993		14.10
10,1.2,2.3	E*	Corby	CCGT	200		412	IN	1993		14.10
1.2,2.3	E*	Peterborough	CCGT	200		405	IN	1993		14.10
3.1,2.3	E*	Roosecote	CCGT		230	229	IN	1991		14.10
3.4, 6(19.5.92), 1.2,2.3	E	**Teesside/Greystones**	CCGT/CHP	850		1,875	IN	1993		
		TOTAL ABOVE			**230**	**3,193**				
2.3	E	Dinorwig	Hydro			1,740	OT	*1984*		
2.3	E	Ffestiniog	Hydro			360	OT	*1963*		
1,2.1,2.2,2.3	E*	Calder Hall	magnox		198	192	OT	1956	1996	0.00
		TOTAL ABOVE			**198**	**2,292**				
2.3	E	FRANCE	external			1,972	LI			8.00
2.3	E	SCOTLAND	external			*850*	LI			11.33
		TOTAL ABOVE				**2,822**				

* Owner Groups: NE = Nuclear Electric, NP = National Power, PG = PowerGen, IN = Independent power producer, OT = Other: BNFL, NGC, LI = Link

Table B.4 Summary of All Plant in England and Wales NGC System as at July 1993

Type of Plant	Number	Capacity in MW	Proportion
Nuclear: Magnox	7	3,485	
Nuclear: AGR	5	6,039	15.8%
Large Coal	12	22,921	
Medium Coal	6	5,356	
Small Coal	8	1,994	total coal: 50.3%
Oil	6	8,486	14.1%
Open Cycle Gas Turbine (OCGT)	25	2,148	3.6%
Combined Cycle Gas Turbine (CCGT)	7	4,713	7.8%
Hydro	7	2,219	3.7%
Link (Scotland and France)	2	2,822	4.7%
TOTAL	**85**	**60,183**	**100%**

B.2 Deterministic Approach

B.2.1 Description of Approach

The Central Electricity Generating Board used scenario and sensitivity analyses to assess the impacts of major uncertainties on its plans for capacity expansion, mainly to support the decision to invest in a new type of plant. Their approach is deterministic, starting with the construction of several plausible future scenarios. Their scenario analysis rested on major scenario drivers and painted interesting pictures of the future, typically reflecting most likely and extreme cases. A detailed electricity planning model is then run for each scenario to determine the optimal mix of capacity over the planning horizon. This optimisation programme is data-intensive and non-transparent but enables the assessment of both marginal plant economics and total costs. The main advantage of such an optimisation is that different constraints can be included. While scenario analysis covers a range of futures, it does not take into account fluctuations within or deviations from each scenario. Sensitivity analysis is needed to explore the uncertainties in individual parameter values and variations of scenarios. In fact, the CEGB relied on extensive sensitivity analysis to defend their estimates in the Sizewell B and Hinkley C public inquiries against opposing assumptions and appraisal methods. The deterministic approach is easy to follow, thus lending itself to credibility and immediate acceptance.

Capacity planning in electricity generation has been traditionally formulated as a resource allocation optimisation problem. It allocates different types of plants, each with different capital and operating costs, to different periods with the further specification of plant capacity to meet pre-specified demand. Without the optimisation formulation, it is more difficult to assess the choice of plant via a marginal cost analysis in the manner of the first pilot study (Appendix A), the amount (unit capacity size and total number of plant) to install in terms of total to meet demand, and the timing of installation by a decision tree as details of production costing which contribute to merit order will be lost, and seasonal plant availabilities and load duration curves are absent. The timing decision is a function of the lead time or construction period, expected demand, existing capacity, and type of plant. Decisions are made at one point in time for all future periods. This kind of deterministic optimisation treats the different periods equally and does not consider contingencies.

B.2.2 Description of Replication

The replication of this approach consisted of spreadsheet analysis to generate the scenarios and then spreadsheet macros to translate them into input files for the optimisation programme. The ECAP (Vlahos, 1991) optimisation programme is a proprietary PC-based application which runs in the Windows operating system and uses Benders' decomposition. ECAP has been validated in (Vlahos and Bunn, 1988b) against CEGB's mixed linear programming mainframe-based MIXLP programme and found to be about 100 times faster. It makes use of iterations to close the gap between lower and upper bounds to a user-defined tolerance level. The smaller the tolerance level, the more optimal the solution, and the longer it takes to reach convergence.

Permutations of demand growth over time, seasonal load duration curves, and fuel escalation rates resulted in 36 different scenarios. The demand uncertainty, for example, can be reasoned as follows: extreme weather conditions contribute to more peaks in demand, translating to a steeper load duration curve for that particular season. The base case contained 8 load duration curves (LDC) to correspond to each of the seasons. On top of the original LDC, we constructed the case for more base load and more peak load, hence ending up with two additional LDCs for each season, totalling 24 LDCs altogether. LDC for season 1, for example, is illustrated in figure B.1.

Figure B.1 Load Duration Curves for Demand Uncertainty

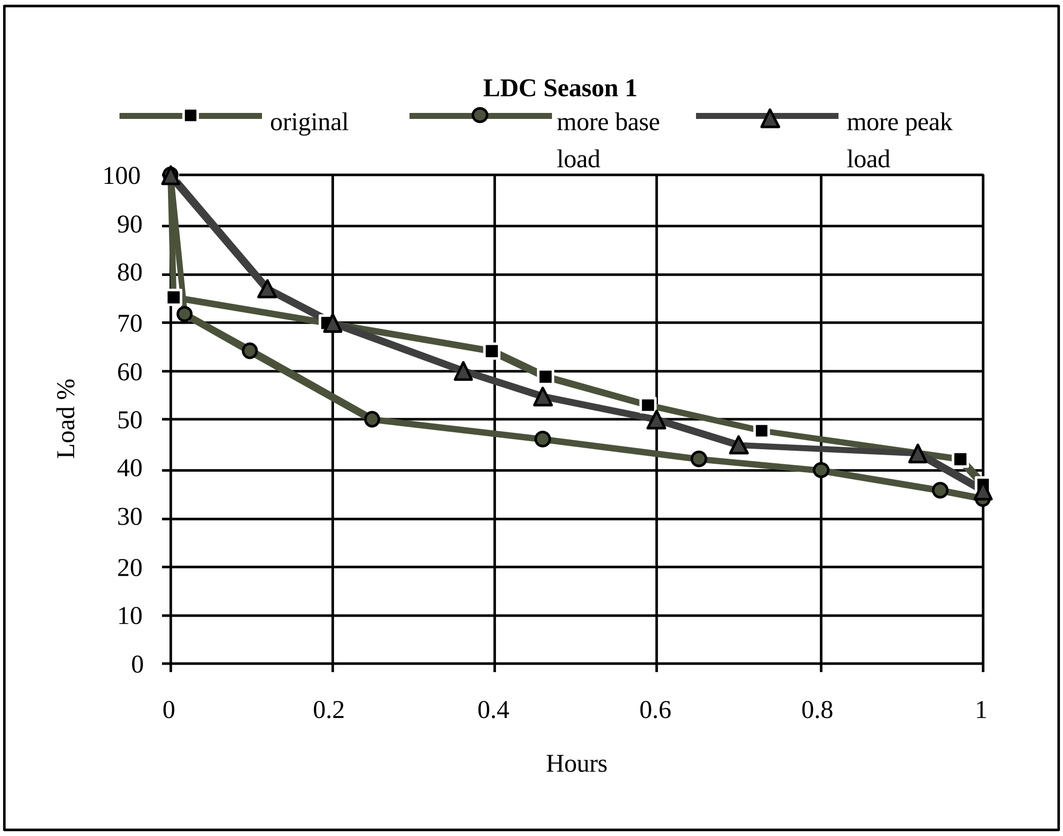
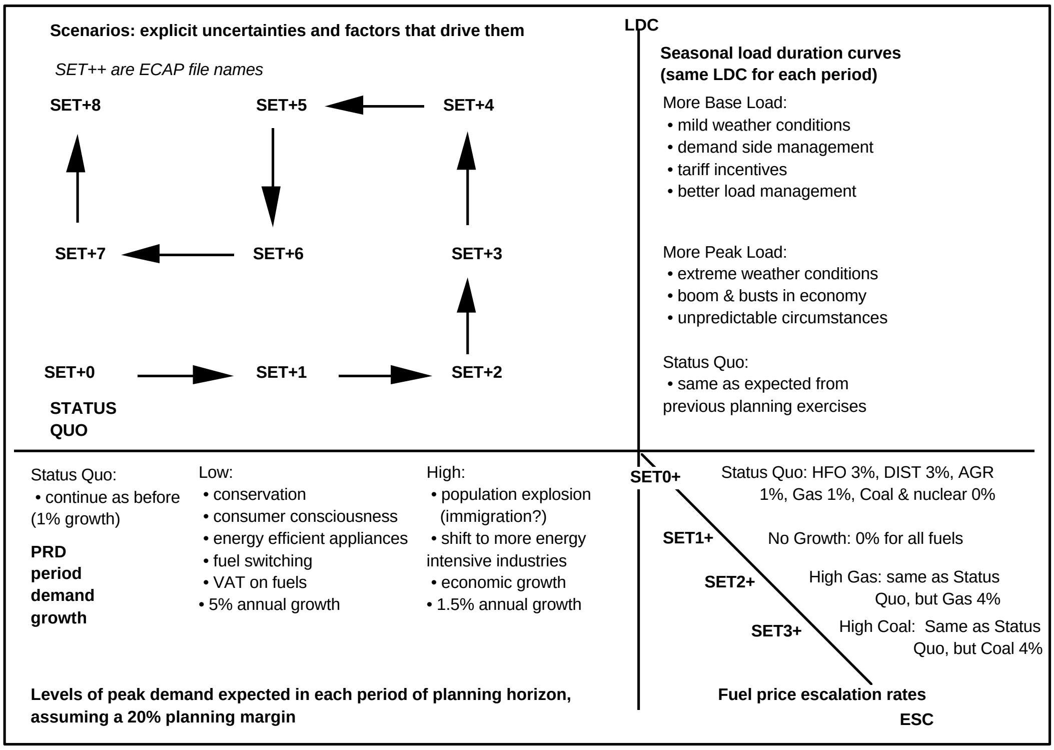


Figure B.2 shows how these three factors are used to generate the scenarios. These scenarios reflect status quo and extreme conditions. Within each scenario, the optimisation programme is run to get the optimal capacity plan. Of the 36 outcome plans, those that generated the highest and lowest optimal expansion costs are then analysed in depth. Next, inputs are toggled to create a plan where new nuclear plants will be economic to install. Sensitivity to planning margin is also tested by comparing the selected scenarios under the status quo 20% reserve margin conditions to 40% at low and high rates of demand growth. We took a short cut, the parameters varied in the sensitivity analysis were the same ones used in constructing the scenarios.

Figure B.2 Scenario Generation



The 65 existing plants in the system total 55,616 MW (or 55.6 GW) of capacity. The breakdown by type of plant and ownership are given table B.3. The base case or status quo scenario takes the updated list of existing plants and subjects them to technical parameter values as used by the former CEGB. No minimum or maximum new capacity is specified in the optimisation, except for renewables. Renewable technology, such as wind and tidal power, are assumed to grow at a rate according to incentives under the Non-Fossil Fuel Obligation subsidy. Availabilities, generation costs, basic seasonal load duration curves, and other factors are assumed not to have deviated from the last CEGB run in 1990. New plant options of the same technology have the same characteristics as existing plants. For example, a new nuclear plant, whether AGR or PWR, has a technical and economic life of 40 years, interest during construction[1] of 4.2, and 1175 MW capacity per unit. The six types of new plant options are nuclear, coal, CCGT for baseload, CCGT for peakload, gas turbine (open cycle), and renewables. A further breakdown is not considered. The first priority in meeting demand is taken up by renewables. The capacity cost per plant per season is the same for plants of the same technology. Generation cost varies marginally for each season. Operations and maintenance (O&M) costs represent an annual fixed cost per plant.

Factors that contribute towards the status quo scenario are called status quo files. The status quo period demand grows at 1% per year starting from 51,400 MW peak demand in 1994. The status quo fuel escalation rates are annually 3% for heavy fuel oil, 3% for diesel, 1% for AGR, 1% for natural gas, and 0% for coal and nuclear. There are two kinds of fuel escalation rates, one for AGR, and the other for Magnox and PWR. Two kinds of fuel escalation rates correspond to British

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[1] Interest during construction can be expressed as a lump sum monetary value, as a rate of interest, or, in this case, a "number of years of interest during construction." This is simply half the construction period.

Coal and imported coal. All oil-fired stations take heavy fuel oil. All gas turbines take diesel (DIST). All Combined Cycle Gas Turbines (CCGT) take natural gas. Plant availabilities and load duration curves are described for each of the eight seasons. These eight seasons correspond to the weekday and weekends of four kinds of season of the year with respect to peak and plateaus. Plant availabilities have more variation than fuels, e.g. four kinds of availability patterns exist for nuclear plants: magnox, AGR, nuclear A, and nuclear B. Availability for new plant options is considerably lower than existing plants as seen in practice. The distribution of seasonal availability over the planning horizon is kept as simple as possible, not more than three sequences per plant. The seasonal load duration curves are taken from old CEGB statistics, with the assumption that overall seasonal patterns of demand have not changed. For extreme scenarios, the LDCs were varied towards more peak or more base-load. The existence of fuel supply contracts implies minimum energy constraints which reflect fuel supply contracts in place, i.e. power stations called to run must meet minimum utilisation levels. Running with and without minimum energy constraints had little impact on the final results, with the only interesting observation being those plants in the merit order which satisfy the minimum energy constraints exactly. Hence, to speed up the optimisation runs, capacity plans under all scenarios have been generated without minimum energy constraints.

In the status quo case, a 20% planning or reserve margin was assumed for all 12 periods in demand growth. This means that minimum capacity required is 20% above the peak demand expected in that period. This assumption was found to be well justified by another study (Bunn et al, 1993) where a system dynamics model found that a 24% planning margin achieved equilibrium conditions in the electricity market. This planning margin is reflected by the setting of the Value of Loss of Load (VOLL) by the electricity regulator, ensuring that there is no incentive to build too much (above 20%) or too little capacity in the long run. Other factors reflect the current assumptions of the industry: 10% discount rate, 10% Non Fossil Fuel Obligation, and 33% corporate tax rate.

The transient nature of the industry means that data accuracy and model precision are not of high priority in this exercise, as the focus is on modelling methodology not policy insight. With 36 scenarios to configure, the replication was designed to generate results quickly by means of short optimisation runs, with minimal variation in input requirements through simplicity and standardisation of specification. For shorter runs, the tolerance level for convergence of the mathematical decomposition-based optimisation algorithm was set to 0.05 instead of the more precise 0.005 or 0.0005. Thus fewer iterations are required to close the gap between the upper and lower bounds for the total cost of the final capacity plan. Tightening the tolerance changes the optimal expansion plan by lowering the total cost at the expense of 12 iterations instead of 4 to reach convergence. The more optimal plan (say at 0.005 tolerance level) calls for building CCGT for peakload as well as base load, building more gas turbines, but much less CCGT capacity altogether. It is assumed that as long as the tolerance level used is same across all scenarios, the results can be comparable.

The 35 non-status quo scenarios are generated by varying the period demand growth in three ways, the seasonal load duration curve in three ways, and the fuel escalation rates in four ways. The status quo period demand assumes a 1% annual growth rate, while the low case assumes only a 0.5% annual growth rate, and the high case of 1.5%. The low growth case is expected when any or all of the following takes effect: conservation measures, increasing consumer consciousness of energy and environment and energy saving schemes, introduction and penetration of energy efficient appliances, fuel switching behaviour of consumers, and VAT on fuels to curb electricity consumption. The high growth case is not very likely to occur since the economy is unlikely to take a sharp turn upwards and grow faster than the previous decade. Neither is it likely to shift to more energy intensive industries and foresee a population explosion in Britain. However, a truly deterministic approach does not take account of the likelihoods, so this aspect is not explored further. Variations of load duration curves merely takes the same seasonal status quo, trimming it down for baseload or lifting it higher for peakload. (This process began with a visual and graphical inspection and adjustment, followed by coordinate inference. A more accurate and defensible method consists of taking demand data directly from the National Grid Company which supplies such information as forecast for future periods and load distribution curves, and then converting them into load duration curves.) In the Sizewell B public inquiry, the CEGB had used negative growth rates for the low scenario and 2.6% per annum for high demand growth. These seasonal LDCs may steer towards more base load if any of the following occurs: mild weather conditions (more stable demand), demand side management, tariff incentives, and better load management on the supplier's side. If the industry evolves more vertically (or incentives for cross functions) such that generators supply electricity and suppliers also generate electricity as the likely trend observed now, then demand side management may become popular.

Fuel price uncertainty is reflected in four ways. The status quo, as stated before, contains escalation rates reflecting today's trends. The no growth case assumes 0% escalation for all types of fuels, a scenario that is likely if all existing and new plants are tied to fixed fuel supply contracts. The high gas case uses 4% instead of status quo 1% annual growth rate for natural gas, reflecting the premium on gas if more CCGTs are built or if major interruptions in supply occur. The current custom of back-to-back contracts for new CCGTs, however, makes it unlikely that a steep growth in gas prices will occur. Finally, the high coal case tags coal prices to 4% instead of 0% pa. The escalation rates of domestic and imported coal are assumed to be the same here. This situation may occur if the closure of coal pits in the UK is a result of an under-estimation of production capacity and demand for coal, i.e. leading to a scarcity of coal. Similarly imported coal may become more expensive but necessary if such a scenario exists. In all scenarios, the discount rate was set at 10%, NFFO at 10%, corporate tax at 33%, and tolerance at 0.05.

B.2.3 Results of Replication

The status quo scenario was examined with respect to the optimal expansion plan, the merit order of plants in the next 15 years, and the relative economics of each plant. Three additional scenarios were generated for in-depth study: those giving the highest and lowest costs and the third arising from the combination of high gas, high period demand, and peakload duration curves. Each scenario was also tested for sensitivity to certain parameters.

Status Quo Scenario

During the next 15 years, the optimal expansion plan prescribes the installation of up to 10,370 MW of new CCGT as baseload, 2050 MW of renewable plant, and building 6014 MW of open cycle gas turbine (OCGT) in the first three years. This amounts to an investment cost of £12.652 billion for the next 44 years. By the year 2010, the newly installed CCGTs would have pushed the just installed CCGTs in 1993 down the merit order. Renewables would, of course, lead the merit order, followed by nuclear plant, links to France and Scotland, coal station, CCGT, oil, and new gas turbine. However, the marginal fuel saving[2] (MFS) of CCGT is substantially lower than the Scottish Link and coal stations just before them in the merit order. OCGTs (open cycle gas turbines) offer no marginal fuel savings as

2 The fuel saving in the total system if this plant is introduced.

they are retained for peakload purposes. Presumably by then, all existing OCGTs would have reached their end of life or else be pushed out of merit completely.

This status quo scenario was also tested for sensitivity to discount rate. At 6% discount rate (interpretation: still in the public sector), more coal and less CCGT should be built. While CCGT may suffice in the earlier years, i.e. the first 15 years, it is more economical to build coal plants in the latter part of the 44 year planning horizon. But as a result, the optimal expansion plan is more expensive by 64%. Coal plants have higher investment costs than CCGTs.

Imposing minimum energy constraints gives slightly higher overall cost but also lowers the utilisation and load factors of plants considerably.

Scenario 1: High coal prices and high demand growth

This is an extreme but unrealistic scenario which gives the most expensive option (£45.4 billion of which the investment cost is £13.95 billion). The average cost of all 36 scenarios was £36.7 billion. Given that coal is not a suitable alternative because of its high price escalation, the need to install CCGT in almost every period to meet high demand makes it very costly. By the year 2010, 18.3 GW of CCGT, 9 GW of gas turbines, and 3 GW of renewables should be installed. By then, all newly installed CCGT would expect to move up in merit and become baseload, hence preceding existing coal-fired stations in the merit order. The load factor of these coal stations fall from 75% in the status quo case to 60% and down to as low as 20%. We would expect the early retirement and mothballing of existing coal plant in such a scenario. The sell-off option was not considered here.

Scenario 2: No growth in fuel prices, base load duration curves, and low demand growth

This combination describes very stable circumstances, hence the plan is least costly of all scenarios. As demand is not expected to grow much (0.5% pa), the total investment cost for the entire planning horizon is only £9.478 billion. New gas turbines in the first 25 years can cope with any peaks in demand. Thereafter, CCGT for peaking load should be built. As with other scenarios, new renewables are built at increasing capacities every year, to reflect the Non-Fossil Fuel Obligation and also the industry's inclination towards more environmentally clean methods of generation. No new nuclear, coal, or baseload CCGT need to be installed. The annual fuel cost in the year 2010 (just after our 15 year evaluation) is almost half that of the status quo case in the same year.

Scenario 3: High gas prices, peakload duration curves, and high demand growth

This is a scenario driven by extremely uncertain factors. However, the results are not as extreme as expected. High gas prices make CCGTs unattractive. High demand growth calls for new capacity. This combination makes coal an attractive option. After the first twelve years, coal plants should be installed every year, amounting to 70.789 GW of total new coal capacity. Meanwhile, peak load duration curves call for more gas turbines to be built, total ling 19.673 GW of OCGT over the 44 year planning horizon. What is more interesting is that by the year 2010, oil stations will have moved up the merit order, replacing CCGT. However, the new open cycle gas turbines will still trail the build-up of CCGTs.

Further scenario analysis

The above analysis prompted further scenario generation to answer two questions. 1) What effect will falling coal prices have on capacity planning? 2) What conditions are necessary to induce the installation of new nuclear plants?

If coal prices fall at an annual rate of 1%, new coal installation becomes attractive but not until later periods, the earliest being the 25th year. New CCGT should still be installed in the early periods to meet rising demand and to replace retired plant capacity. New capacity to meet the high rate of demand growth will thus be met by new CCGT in the early periods and new coal in the later periods.

The easiest way to create a nuclear scenario, i.e. to make the nuclear option more attractive, is to make other fuels less attractive. Hence, the fuel escalation rates for coal and gas were raised to a high of 4% per annum, while no escalation was made for nuclear. No coal plant but only 1.875 GW of CCGT should be built. Starting in the 7th period (year 2012), a substantial 11.6 GW of nuclear capacity should be installed, rising to a total of 37.5 GW by the end of the planning horizon. Diesel is also more attractive, hence new gas turbines should be installed every year except two periods. If we lower the discount rate from 10% to 6%, i.e. assuming a public sector scenario, then even more nuclear capacity (total of 44.7 GW) should be built and earlier too (4th period instead of 7th). This additional nuclear capacity displaces much of the gas turbines in the 10% discount rate case. By the year 2010, the order of merit is obvious: renewables, nuclear, links, coal, oil, CCGT, and OCGT. The high operating cost of OCGT forces it to the bottom of the order in all cases.

Sensitivity Analysis

Sensitivity to tolerance level and minimum energy constraint has already been discussed earlier. Sensitivity to planning margin was conducted to assess the impacts of over or under capacity.

A 40% margin boosted up the minimum capacity levels required of all periods in the high growth and low growth cases. These were applied to the four scenarios described above: status quo, high coal price and high demand growth, no growth, and high gas price. These combinations led to 8 scenarios with 40% planning margin implied in the period demand growth. The results were examined and compared with scenarios closest to them, not necessarily mentioned above. The striking outcome is that in all 8 scenarios, 16.3 GW of new gas turbine (OCGT) plant should be built in the first three years. The fastest way to meet a 40% planning margin is by constructing those fossil fuel plants which have the lowest interest during construction (hence shortest construction time) and much lower O&M cost than that of CCGT. In general, the additional capacity is met by building more gas turbines. Other characteristics do not change very much, if at all. Another way of looking at sensitivity to planning margin is to vary the planning margin per period, e.g. start with 20% and gradually move up.

B.2.4 Conclusions and Extensions

Several criticisms of the deterministic approach lead to the consideration of a probabilistic approach. But the deterministic approach itself can be extended in several directions towards more model completeness. The values we used have been central estimates, hence the extreme scenarios are symmetric around the base case. Asymmetry is more likely the case, and should be considered. We have only looked at two types of uncertainties. As mentioned in Chapter 2, the types of uncertainties may change over time (in relative importance). Hence it may be useful to include other uncertainties. We have taken a short cut of using the same uncertain parameters in the construction of the scenarios for sensitivity analysis. Some aspects of the model are more difficult to change because they require re-configuring the optimisation programme. However, they are necessary to reflect the electricity market: different discount rates for different plants or ownership, optimisation by ownership or by different types of load, and making it more user friendly for quick changes.

B.3 Probabilistic Approach

B.3.1 Description of Approach

In the Sizewell B public inquiry, the inspector (Layfield, 1987) recommended that the CEGB should include probabilities in their analysis of the capacity expansion decision. A more rigorous analysis of uncertainty was only one of several reasons for using a second model. A second model of the form described in Evans (1984) was needed to test CEGB's model because of the complexity and importance of the calculations. It was also necessary to derive cost estimates for different sets of assumptions especially to test the sensitivity of the results to changes in specific assumptions. A probabilistic method was regarded as complementary if not more informative for analysing uncertainty, particularly if sensitivity tests give mixed results, i.e. some favourable some not. A probabilistic method enables the results to be drawn with a high degree of confidence, whereas a deterministic method gives no indication of the likelihood of results. It helps to resolve conflicting views. Furthermore, a probabilistic approach would have merit if the results from a deterministic approach were not robust. However, this implies that CEGB's approach must address robustness by accounting for very extreme and adverse scenarios.

A probabilistic approach appeared more favourable given the harsh attacks on the deterministic CEGB approach. Evans (1984) called it probabilistic decision analysis but in actual fact used the techniques separately, decision analysis merely to structure the problem without any computation in the decision analytic sense. Critics of the CEGB model complained of the underestimation of uncertainty and tendency to err on the side of optimism. The uncertainties prevalent in long planning horizons imply a danger of using single estimates as a basis for decision making. Evans' (1984) approach has been used in Kreczko et al (1987) and Evans and Hope (1984). Evans did not consider uncertainties in discount rate or plant life times as they were not a concern ten years ago. However, the choice of discount rate and length of operating lives of nuclear plants have become major issues now. This goes to show that no matter how sophisticated the model, there are some things that cannot be foreseen and the resulting model may be incomplete.

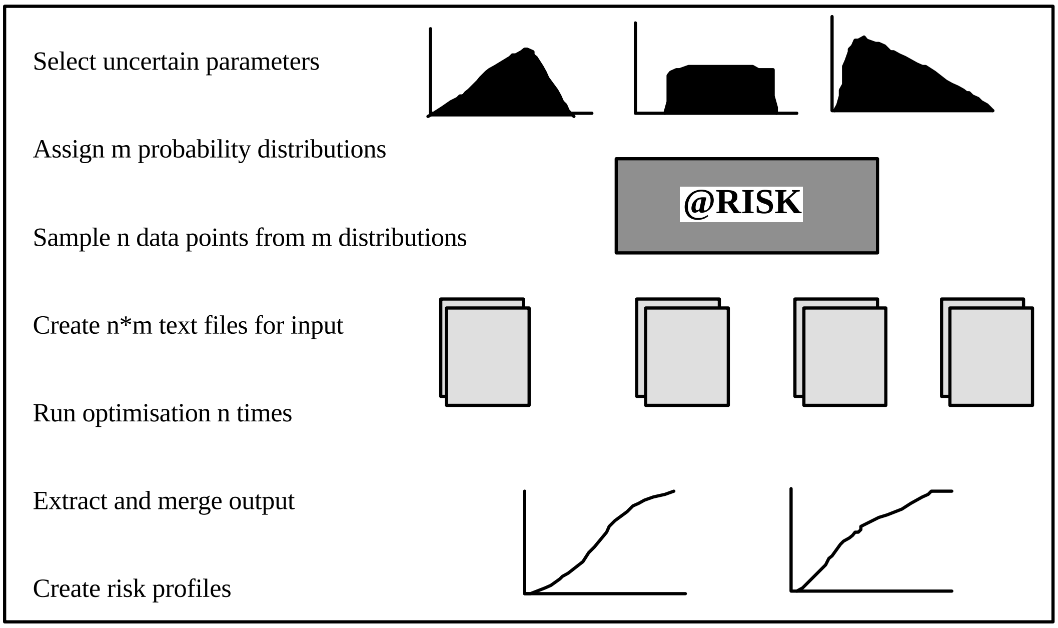
To keep the replication simple and tractable, we confine this approach to an application of risk analysis, that is, expressing uncertainties as probability distributions, a step beyond merely attaching discrete probabilities to values. Risk analysis is performed using the same optimisation technique of the deterministic approach but with Latin Hypercube Sampling. Effectively, the deterministic approach is simulated hundreds of times to arrive at outputs that can be summarised in cumulative probability distributions which are called risk profiles. This interpretation of Layfield's recommendation is based on conclusions of McKay et al (1992), that "uncertainty in the output due to uncertainty in input values can be described by probability distributions." Uncertainty due to model structure is not discussed here, as it is assumed that uncertainties expressed in the output are due entirely to the input configurations. In the extreme, uncertainty analysis, according to Inman and Helton (1988) involves the determination of the variation or imprecision in the output that results from the collective variation in the inputs. The main departure from the deterministic approach comes from the introduction of probabilities which adds another dimension to value and insight.

B.3.2 Replication and Results

The replication follows that of Evans (1984) but with fewer input probability distributions so that the uncertainties can be compared with the deterministic approach. The method of replication is illustrated in figure B.3.

An incremental and exploratory approach to modelling was needed to establish the feasibility and limitation of available hardware and software. Simple probability distributions were assigned to a few uncertainties. After the runs had been smoothly initiated and completed, the number of input uncertainties were increased. Triangular distributions depicted the simplest type of asymmetric distributions, easy to specify and meaningful to the user. In practice, the choice of distribution parameters such as mean and mode is difficult to substantiate.

Figure B.3 Replication of the Probabilistic Approach



Meaningful input probability distributions are expected to deliver meaningful output distributions given enough iterations. 100, 300, and 1000 iterations were tested. Whilst 100 iterations can be completed in 2 days, 1000 iterations required 2 weeks. The number of iterations is the same as the number of data points in distribution sampling. The inclusion of additional uncertain parameters requires an increase in the number of iterations to maintain the same level of sampling continuity. Since the exact relationship between number of distributions and number of iterations was not clear, more iterations were used than necessary.

The input distributions were specified in the @RISK add-in package (Palisade Corporation, 1992) to Excel spreadsheet. Latin Hypercube Sampling promises a more efficient randomisation design compared to Monte Carlo (completely random sampling) and other types of stratified sampling methods. Fewer iterations, i.e. smaller samples, are needed to recreate the probability distribution. These data points were then extracted from the @RISK output spreadsheet and consolidated into an equivalent number of text files for input into the optimisation programme.

Automating the process of specifying input data files, running the optimisation programme, and saving the output files accordingly was accomplished by writing a series of Excel macros to perform the simulation iteratively. Three applications were used for simulation: Excel, PFE file editor, and BENDERS (optimisation algorithm in ECAP). The time to convergence of decomposition depends on input files, in particular, the escalation rate for the fuel (diesel) used in gas turbines. Because it was impossible for BENDERS to signal the end of its run to the parent Excel macro, it was necessary to pre-specify how long Excel had to wait in this multi-tasking WINDOWS environment. If this could be improved, say by use of a window handler facility, the simulation could take less time.

The optimisation programme produced five different files for each run. Two were discarded and three files retained for each run. The intermediate results file INR was kept to monitor the duration of run, as it was used in monitoring and subsequent adjustment of the waiting time of the parent Excel macro. The OEP file contained the optimal expansion plan in terms of investment, operating and total costs and also newly installed capacities per type of plant per period. The production costing results PCR file contained the merit order of all plants in the system for the periods requested -- first, second, and fifth periods in the planning horizon.

Inputs and outputs of the deterministic and probabilistic approaches are largely determined by the input and output files of the core optimisation programme ECAP. Table B.5 lists the input data files. Table B.6 lists the output data files.

Table B.5 Input Files to ECAP

File Name	Name	Description
LDC	Load Duration Curve	Demand for electricity described by the load duration curve which is approximated by a step function. 8 seasons are specified.
PRD	Period Definition	Defines the periods of the planning horizon and minimum and maximum total plant capacity. Reserve margin.
ESC	Escalation Rates	Fuel escalation data which determines how the variable plant operating costs are escalating, defined by escalation codes and patterns.
OLD	Existing Plant File	Plants in the system, e.g. table B.3, containing name of plant, scrapping life in years, capacity in MW, availability, generating cost, escalating code for fuel used.
NEW	Plant Alternatives	Technology alternatives, description by type of fuel, escalation rates, economic and technical lives in years, number of years of interest during construction, standard plant size in MW, generating cost escalation code, fixed operating cost.
AVL	Availability	Availability patterns and codes for plants for 8 seasons in the year.
TOP	Take or Pay File	Seasonal minimum utilisation constraints used to model the take-or-pay obligations of generators resulting from fuel contracts.

Table B.6 Output Files from ECAP

File Name	Name	Description
OEP	Optimal Expansion Plan	Main output file: investment and retirement schedule containing all existing plants and new plants that meet objectives in cumulative block form.
NCC	Net Capacity Costs	Annual Capital Cost + Fixed operating Costs - Fuel Savings for all new plants in the middle year of all periods that the plants operate.
PCR	Production Costing Results	Details of plant operation in the middle year of each period of planning horizon, displayed according to merit order.
SMP	System Marginal Price	Information about SMP's in different seasons and periods of the planning horizon.
INR	Intermediate Results	All intermediate expansion plans before convergence to the final optimum.

B.3.3 Extensions of Probabilistic Approach

The use of probabilities introduces the issues of choice of probability distribution and sampling method as well as subjective probability elicitation and encoding. Triangular distributions were used because they were simple to specify, requiring only three parameters, and yet reflected asymmetry. There are other probability distributions that may be more appropriate for different parameters, i.e. not all uncertain parameters display such asymmetry. Latin Hypercube Sampling was used because it was most efficient. However, there are other sampling methods in the domain of uncertainty analysis proper. Morgan and Henrion (1992) describe extensively different types of uncertainty analysis and uncertainty propagation methods such as stratified sampling and importance sampling. Different planners and different utilities will have different views on which probabilities to use.

While we can increase the number of uncertain parameters considered, we must also beware of the dimensionality problem of considering them all simultaneously. With sampling, there is also the question of independence of probabilities to consider. The few uncertainties considered here alone have already led to problematic display of output due to the sheer volume of data points in the output distributions.

Another interpretation of this approach includes the use of risk analysis to screen out dominated or infeasible scenarios before the "real" analysis. This reduces the problem size. Rigorous risk analysis is essentially a test of robustness. There is also a facility to combine sensitivity analysis with risk analysis. But these tests come at the expense of increasing complexity and dimensionality.

B.4 Decision Analytic Approach

B.4.1 Description of Approach

The third modelling approach encompasses deterministic and probabilistic aspects of uncertainty modelling. Decision analysis is a technique that structures the problem in terms of decisions and chance or uncertain events. The impact of uncertainty is resolved in stages over time. The Electric Power Research Institute (EPRI) in the US has funded and sponsored a number of planning projects which used decision analysis as the main technique for structuring and analysis of uncertainty. The essence of EPRI's methodology is explained in Barrager and Gildersleeve (1989). Characteristics of the deterministic approach can be elicited from various EPRI-sponsored projects, e.g. Cazalet et al (1978), Baughman and Kamat (1980), Hobbs and Maheshwari (1990), Keeney and Sicherman (1983), and Keeney et al (1986).

Capacity planning can be defined by three types of decisions relating to the type, size, and timing of plant investment. Sullivan and Claycombe (1977) suggest a sequential approach. First decide on the type of plant, which is based on investment and operating cost and expected demand. Then decide on size, which is based on type, economies of scale in investment cost, and system-wide reliability requirements. Finally decide on timing. The timing decision is based on the type, size, system reserve requirements, future load characteristics, and economic forecasts.

The Over and Under Model (Cazalet et al, 1978) can be adjusted to suit the UK context. Instead of reliability as an objective, over and under capacity is propagated by profitability in relation to the implicit reserve margin set by the pricing formula (VOLL, value of loss of load). This extends to the multi-staged project decision by discounted cashflow.

When restructuring the capacity planning problem in the decision analytic approach, the focus changes from the system as a whole to that of sequential decisions regarding individual plants or characteristics of these plants. A state of the art decision software DPL (ADA, 1992) enabled the use of decision trees and influence diagrams to structure various prototypes investigated.

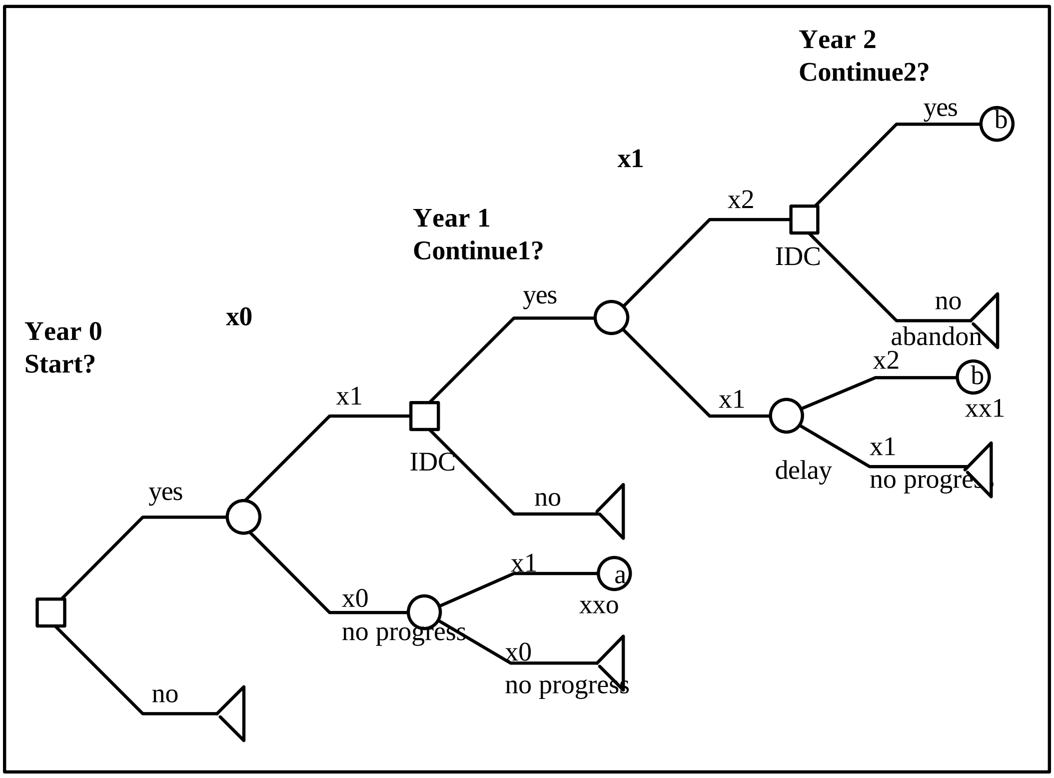
Within a decision analysis framework, capacity planning becomes that of generating alternatives, evaluating them, and selecting an appropriate course of action. The three types of decisions, namely, technology choice, capacity size, and timing can be considered separately or together. The technology choice model of Keeney et al (1986) exemplifies the stand-alone analysis of the technology decision. However, many other studies have argued the need to consider all three decisions in the context of optimising the entire system (portfolio) because any optimal allocation affects merit order. This multi-staged analysis of decisions results in the introduction of a specific technology of a specific capacity size at a specific future date. The decision model replicated follows that of Cazalet not Keeney.

B.4.2 Three Prototypes

Unlike the previous two approaches, the decision analytic approach is not based on optimisation by which capacity planning can be fully specified. Model specification in decision analysis centres around the structure rather than the data intensiveness of previous approaches. Structure is characterised by symmetry or asymmetry of the decision tree, repetitive decision sequence, number of alternatives, and other distinguishing features of decision trees. Alternative structures of capacity planning can be examined via the construction of prototypes. A prototype refers to a model configuration through which aspects of the approach can be investigated. Prototypes combine features of the above studies and feasible formulations of capacity planning in the UK context. The simplest is the single project timing decision in which the type and size of plant have already been determined. Next is the technology choice model, i.e. a decision regarding the selection of one of two competing technologies. The first prototype focusses on the multi-stage nature of planning decisions. The second shows the resolution of uncertainty. The third looks at technology choice as a function of annual costs. Although other formulations are possible, these three prototypes capture the most important aspects of capacity planning that can be modelled in decision analysis.

Figure B.4 shows the first prototype configuration. At each period, the decision maker can choose to continue or abandon the project. If he/she chooses to continue, there is still an uncertainty about delay. Let the current stage be $\boldsymbol{i}$. If the next stage advances to $\boldsymbol{i+1}$, i.e. *progress*, then a payment of the interest during construction (IDC) is incurred. If the next stage remains at $\boldsymbol{i}$, then there is a *delay* and a delay penalty must be paid. If the following stage still remains at $\boldsymbol{i}$, then there has been *no progress* and a no-progress penalty must be paid. If this stage is 0, then the project has been *abandoned*. The penalty values are levied as follows: a *delay* implies interest accumulation (extra interest payment if the construction cost is borrowed in full or else the cost of extending the borrowed funds to cover capital expenditure) or the difference between interest earned and paid and ongoing recurrent costs. *No progress* implies some kind of ongoing cost that has to be paid. *Abandonment* of a project implies a payment of a one-off fee to end the contracts. Once the project is *completed* after 3 stages, it can begin to earn revenue. The revenue is determined by the actual demand and level of total capacity in the system. Demand is a chance event. Demand in each period is conditional on the demand probability of the previous period. This model allows discrete uncertain events to be introduced at any stage. In addition, structuring the problem in this manner allows the consideration of the impact of delays.

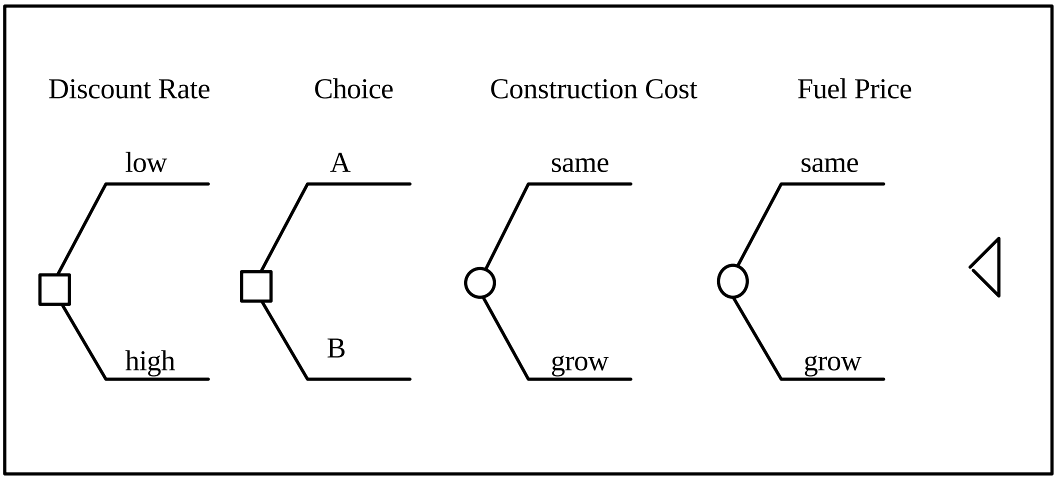
Figure B.4 Prototype One: Single Project



B.4.3 Marginal Cost Analysis

Marginal cost analysis as employed in the first pilot study (Appendix A) is useful for comparing plant alternatives that differ in technology (type), size, and timing. A simplified spreadsheet is linked to an influence diagram model. Different kinds of uncertainties are inserted in the decision tree to show their impact on cost. In figure B.5, the choice of discount rate is determined first, followed by the type of plant (according to thermal efficiency).

Figure B.5 Prototype Two: Marginal Cost Analysis



The technology choice decision can also be evaluated by a typical annual cost breakeven analysis as prototype three. Here fixed and variable costs for a typical year of operation are compared against an equivalent annuitisation of competitive electricity prices. The electricity price of an equivalent operating technology is converted to an annual cost figure for comparison. A plant is only worth building if it satisfies two conditions. One, it can be bid into the pool. Two, it can be profitably operated.

The decision tree allows us to focus on different sequences and order of decisions and uncertainties. However, without constrained optimisation, decision analysis cannot capture the details of plant for merit ordering and other operational intricacies of power generation.