

National power system planning

AUTHOR: Asko Vuorinen, Managing Director, Modigen Ltd.

In this second article based on his book "Planning of Optimal Power Systems" Asko Vuorinen explains how national power systems are planned.

The main target of national power system planning is to find an optimal capacity mix in the system which either gives minimum costs or maximum profits. Minimizing the total system cost is the main method used by national utilities, while maximizing profits has been the preferred goal for private companies.

GENERATION COST EVALUATION

Assumptions

This analysis has been made at an ambient temperature of +30°C at a site to be 100 m above sea level. The assumed power

system has a 10 GW peak load and 52 TWh electricity consumption. The alternative power plants include nuclear, coal, gas, oil and renewable technologies.

Oil-fired plants

Oil-fired plants include heavy fuel oil (HFO), light fuel oil (LFO), and crude liquid biofuel (LBF) diesel engine plants. The HFO diesel engine (DE-160) plant has ten Wärtsilä 18V46 diesel engines. The HFO and LBF diesel engines will operate more than 1000 h/a and have been equipped with SCR denox-systems. The LFO and LBF diesel engine plants utilize twenty Wärtsilä 20V32 diesel engines.

The gas turbine plants can use only LFO and can be built using either aero-derivative or industrial gas turbines. The aero-derivative gas turbine plant includes four 40 MW turbines. The industrial gas

turbines have one 110 MW turbine. The LFO-fuelled plants are assumed to operate less than 1000 h/a without denox-system.

Gas-fired plants

Gas-fired plants include a gas turbine combined cycle (GTCC-330), a gas engine (GE-160), an aero-derivative gas turbine (ADGT-160) and a dual-fuel engine plant (DF-160). The GTCC-330 plant has two 110 MW gas turbines and one steam turbine. The output of the plant at site conditions is 330 MW. The aero-derivative gas turbine plant (ADGT-160) has four 40 MW turbines. The industrial gas turbine (Ind. GT-110) plant has one 110 MW gas turbine.

The gas engine plant (GE-160) has twenty Wärtsilä 20V34SG engines. The dual-fuel plant (DF-160) has ten Wärtsilä 18V50DF engines. The combined output of the two plants is 160 MW. The combined heat and power production plant (CHP) has twenty Wärtsilä 20V34SG gas engines, and a heat recovery boiler with a bypass in each of the boilers.

Other plants

Other power plants analyzed include nuclear, coal, biomass and wind power plants. The nuclear plant has one pressurized water reactor (PWR) and a 1500 MW output.

The coal-fired plant has a fluidized bed boiler and one reheat steam turbine with supercritical steam values and an output of 500 MW. The coal-fired plant includes both desox- and denox-systems. The 160 MW biomass plant employs a steam plant, which is fired by sawdust, bark, and crushed wood.

Capital cost evaluation

Capital costs of power plant alternatives have been evaluated using the formula $CC = FCR \times I$, where CC = capital costs, FCR = fixed charge rate and I = investment costs (Table 1). Investment costs include turnkey plant costs and owner's costs →

	Output (MW)	Efficiency (%)	Investment costs (I) (EUR/kWe)	Fixed costs (Fc) (EUR/kWa)	Variable costs (Vc) (EUR/MWh)
Oil-fired plants					
- DE-160 HFO	160	43	815	94.8	85.2
- DE-160 LFO	160	41	630	68.1	108.9
- DE-160 LBF	160	41	815	89.8	118.2
- AD GT-160 LFO	160	36	715	76.6	124.4
- Ind GT-110 LFO	110	31	530	60.9	154.9
Gas-fired plants					
- GTCC-330 gas	330	49	1050	134.6	66.7
- DF-160 gas	160	43	830	114.1	73.8
- GE-160 gas	160	42	775	107.7	75.0
- AD GT-160 gas	160	38	875	120.3	86.1
- Ind. GT gas	110	31	645	106.8	102.1
- CHP-160 gas*	160	42 (85%)	845	121.6	39.3
Other power plants					
- Nuclear-1500	1500	35	2670	281.0	171
- Coal-500	500	40	1495	166.2	47.6
- Biomass-160	160	34	1510	172.9	44.4
- Wind-160	160	-	1200	126.0	12.0

* CHP plant has 85% total efficiency

■ Table 1. – Cost estimates of alternative power plants.

including interest during construction.

Capital costs have been evaluated using a 25-year lifespan and 8.1% discount rates. The fixed charge rate (FCR) is then evaluated based on the formula $FCR = (r(1+r)^n)/((1+r)^n - 1)$, where r = costs of capital and n = lifespan of the power plant.

Operation and maintenance costs

Fixed operation and maintenance costs (Fom) include plant operating personnel, taxes, insurances, and other services. Variable operation and maintenance (Vom) costs include maintenance costs, as well as material and waste costs. Material costs include materials for denox- and desox-systems and lubricating oil. Waste costs include nuclear waste handling and the costs of CO₂-emission allowances.

Fuel costs

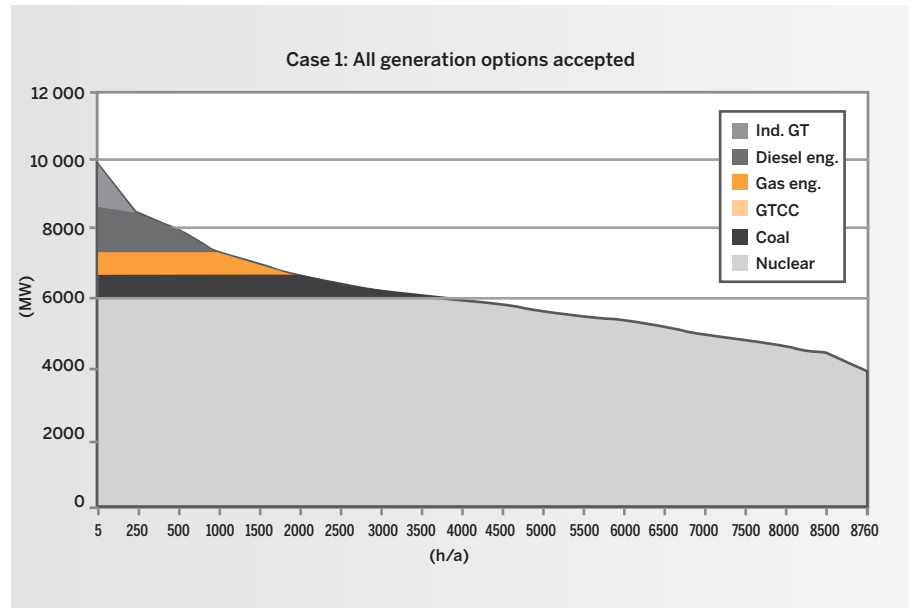
Future prices of fuels have been evaluated by calculating linear trends from the historical values from 1994-2005. It is then assumed that these trends will continue during the 25-year operation time of the power plants between the years 2011–2035.

Levelized prices of fuels have been evaluated by discounting future prices of fuels to the start of operation: liquid biofuel (LBF) 45.6 EUR/MWh, light fuel oil (LFO) 36.3 EUR/MWh, heavy fuel oil (HFO) 25.7 EUR/MWh, 26.5 EUR/MWh, coal 7.6 EUR/MWh and nuclear 4.0 EUR/MWh.

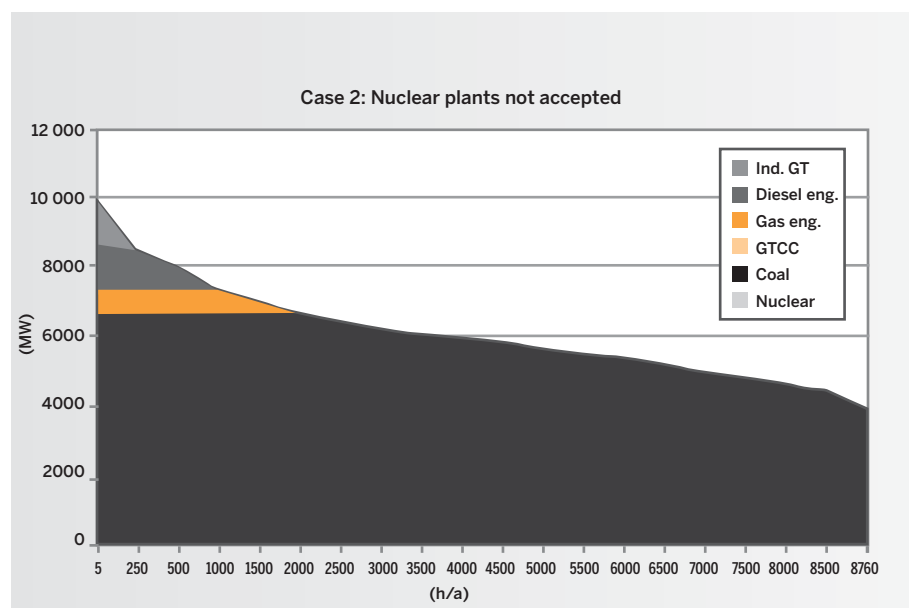
Generation costs

Generation costs (G_c) of alternative power plants can be evaluated using a tariff formula $G_c = F_c/t + V_c$, where F_c = fixed costs, t = full power hours and V_c = variable costs. The parameters of the tariff formulas are given in Table 1.

The optimization starts by studying the lowest cost alternatives for each full power hours (t) range. The break-even costs of peaking plants can be found when the costs of a light oil-fired industrial gas turbine plant (Ind. GT-160) and a diesel engine plant (DE-160) are at the same level, which is at 157 h/a. Thus diesel engines are the most economical above 157 hours, and industrial gas turbines when t is below 157 hours. It should be noted, however, that industrial gas turbines are seldom used in peaking applications, since they cannot be started up in 10 minutes, which is the requirement



■ Fig. 1 – Optimum generation mix with all options open.



■ Fig. 2 – Optimum generation mix without nuclear plants.

for peaking plants in most systems.

The break-even costs of a diesel engine plant (DE-160) and a natural gas-fired gas engine plant (GE-160) can be similarly found at 1170 hours. When annual operating hours are less than 1170 hours, the diesel engine yields the lowest costs. Gas engines are the most economical at levels above 1170 hours. Diesel and gas engines can meet the 10 minute start-up requirement.

Similarly, break-even costs for a gas

engine and a gas-fired combined cycle plant are at 3240 hours. But the break-even costs between a gas engine plant and a coal plant are at 2140 h/a. Thus, a gas engine plant has the lowest costs between 1190 and 2140 hours annually. The gas turbine combined cycle plant has higher costs than the coal plant. The break-even costs of a coal plant and a nuclear plant are then at 3760 hours, while the break-even costs of biomass steam plants and LBF diesel engine plants are at 1125 hours.

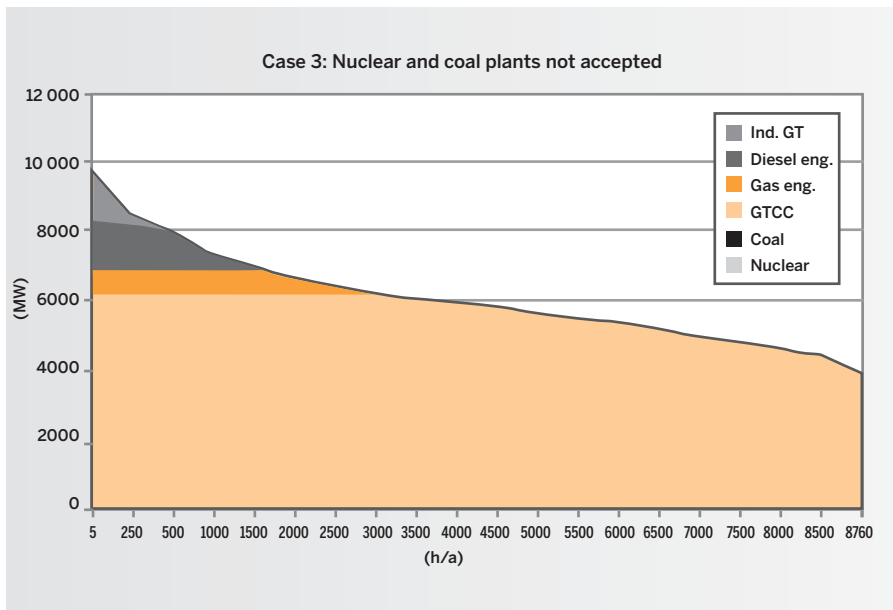


Fig. 3 – Optimum generation mix without nuclear and coal plants.

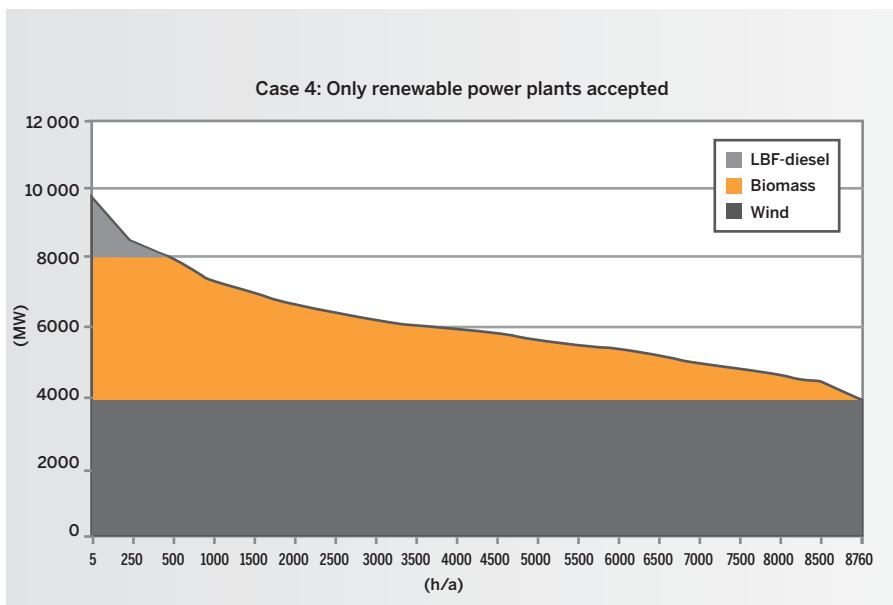


Fig. 4 – Optimum generation mix with renewable plants.

Power plant	Full power hours (h/a)
LFO GT plant	0 - 157
LFO diesel plant	157 - 1170
Gas engine plant	1170 - 2140
Coal plant	2140 - 3740
GTCC plant (without coal)	3240 - 3740
Nuclear plant	3740 - 8760
Gas-fired CHP plant	770 - 5800

Table 2. – Lowest cost ranges of power plants.

The lowest cost for plants at different operation times have been given in Table 2. It should be noted that a gas-fired CHP plant is the lowest cost alternative throughout almost the full range. A CHP plant can be used only if the heat load is needed for district heating, cooling, or industrial process needs.

MINIMIZATION OF POWER SYSTEM COSTS

The goal of optimization is to minimize the total generation costs of the national power system. Four cases have been studied as follows:

Case 1: All generation options accepted (nuclear)

The optimum power generation mix in the system, if all of the above options are open, has been evaluated in Figure 1. The duration curve segments have been filled so that all available plants will be operating only during hours of lowest costs given in Table 2. The baseload would be generated using nuclear power plants, the intermediate load by coal-fired plants and gas engines. The peak load would be generated using light fuel oil-fired diesel engines and gas turbines.

Case 2: Nuclear plants not accepted (coal)

If nuclear power plants are ruled out for whatever reason, coal-fired plants would replace them (Figure 2). In this case, about 97% of the electricity in the optimum system will be based on coal. The peak load generation would be the same as in Figure 3.

Case 3: Nuclear and coal plants not accepted (gas)

If both coal and the nuclear fuel plants are omitted, coal plants would be replaced by gas combined cycle plants (Figure 3). The generation mix would consist mainly of gas-fired plants. This would mean that 97% of generation would come from natural gas.

Case 4: Only renewable power plants accepted

Finally, if all nuclear and fossil-fired plants were replaced by biomass, liquid biofuel and wind energy plants, the optimal generation mix is given in Figure 4. Wind power is only available in baseload, but would need a lot of back-up power. In this case only 10% of wind →

power can be considered as available capacity during peak load. The system would need regulating reserves of about 20% of wind capacity (2600 MW), which can be built using LBF engines.

Optimal capacity mix

The optimum power generation capacity in megawatts in the 10,000 MW system has been evaluated in Table 3. Case 1 (nuclear) would have the lowest generation costs of 63 EUR/MWh. Case 2 (coal) has the second lowest costs at 77 EUR/MWh. The total costs of cases 3 and 4 will be 90 EUR/MWh and 83 EUR/MWh respectively.

MAXIMIZATION OF PROFITS

In free electricity markets, the shareholder value of a utility company depends on the profit. Thus private investors try to maximize profits by building a system in which the electricity prices are high but the electricity generation costs are lowest.

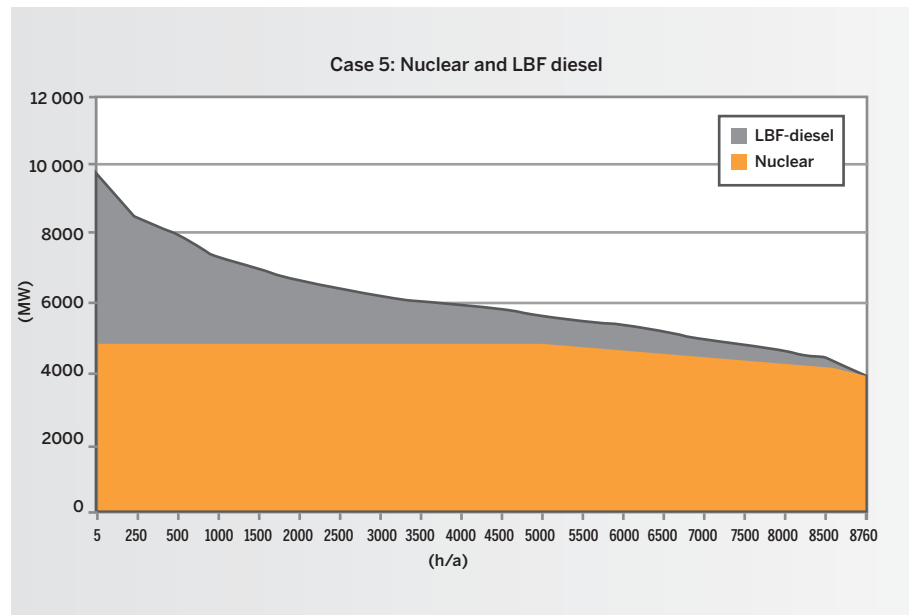
Competitive electricity prices in the power system should be based on the variable costs of the marginal plant during each hour. Prices of electricity based on marginal costs of the marginal power plant in cases 1, 2, 3 and 4 respectively will be as follows: 43.9 EUR/MWh, 61.2 EUR/MWh, 80.3 EUR/MWh and 52.8 EUR/MWh. Incomes and net profits have been evaluated for each case in Table 4.

Maximum profits can be found if prices are based on the most expensive variable costs 100% of the time, but most generation takes place using low variable cost nuclear plants. Highest net profits are obtained with nuclear/LBF (Case 5, Figure 5), in which electricity prices are always 118.6 EUR/MWh, but total costs are lower.

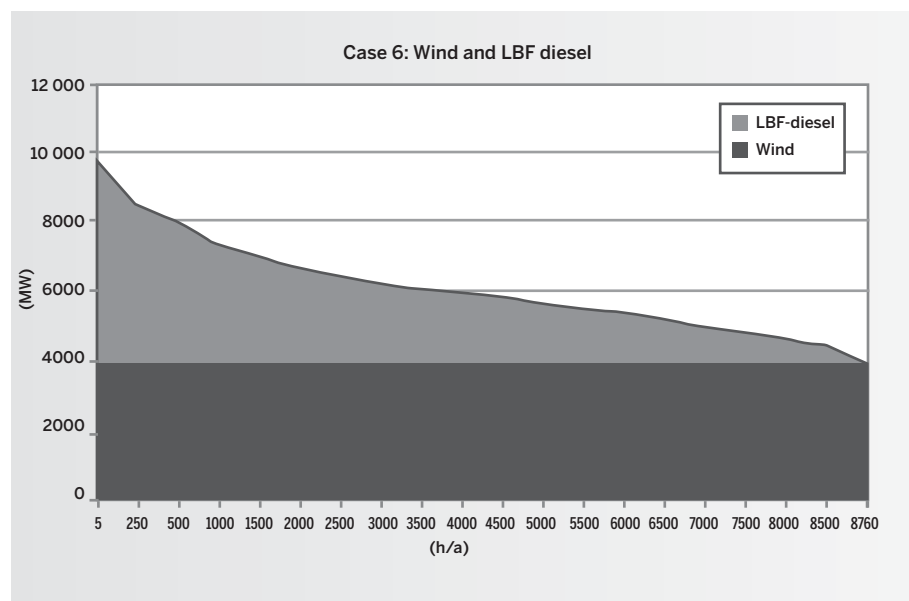
Case 6 (Figure 6) shows wind power producing the baseload and an LBF diesel plant producing the peak load. In this instance, the price of electricity is always 118.6 EUR/MWh, corresponding to the marginal costs of LBF diesel plants. Costs of power generation correspond to the variable costs of wind power (12 EUR/MWh).

SUMMARY AND CONCLUSIONS

The capacity mix of a national power system can be optimized by evaluating the generation costs of alternative power plants at site conditions using leveled prices of fuels. There are two methods of



■ Fig. 5 – Nuclear and liquid biofuel (LBF) mixed power system. Nuclear plants produce the baseload and LBF plants produce the peak and intermediate load.



■ Fig. 6 – Wind and liquid biofuel (LBF) mixed power system. Wind power plants produce the baseload and LBF power plants produce the peak and intermediate load.

optimization: to minimize the generation costs or to maximize the profits.

The lowest costs can be obtained by employing nuclear and CHP plants for the baseload having 60% of the capacity. The coal-fired plants and gas engine plants in the intermediate load with 15% of the capacity. Peak load plants should be filled by diesel engines and industrial gas turbines having 25% of the capacity.

If the system is planned with the goal of maximizing profits, then the baseload should be filled with nuclear plants or wind energy plants having 40-50% of the total capacity. The intermediate and the peak load should be filled with liquid biofuel plants having 50-60% of the capacity. In this case, the price of electricity will be high and generation costs will be low.

Alternative	Case 1 Nuclear	Case 2 Coal	Case 3 Gas	Case 4 Renewable
- Nuclear	6 200	-	-	-
- Coal	700	7000	-	-
- Gas combined cycle	-	-	6500	-
- Gas engines	700	800	800	-
- LFO diesel engines	1500	1400	1650	-
- LFO gas turbines	1500	1400	1650	-
- Wind turbines	-	-	-	13,000
- Biomass steam turbines	-	-	-	4300
- LBF diesel engines	-	-	-	7700
Total	10,600	10,600	10,600	25,000
Average costs EUR/MWh	(63.3)	(76.6)	(90.1)	(82.8)

■ Table 3. – Optimal power generation capacity (MW).

Case		Price of electricity (EUR/MWh)	Incomes (MEUR)	Costs (MEUR)	Net profit (MEUR)
1)	Nuclear	43.9	2276	3286	- 1008
2)	Coal	61.2	3173	3972	- 798
3)	Gas	80.3	4193	4677	- 484
4)	Renewable	52.8	2750	4294	- 1544
5)	Nuclear and LBF	118.6	6167	3980	2186
6)	Wind and LBF	118.6	6167	4674	1493

■ Table 4. – Net profits of alternative 10,000 MW power systems.

The need of ancillary services was not evaluated. In the real world the operation and regulation reserve requirements tend to increase the share of flexible power plants. In the optimal system, about 30-40% of capacity should be filled by gas engines, light fuel oil-fired diesel engines and gas turbines. Additionally, the peaking power plants should be capable of being started up in ten minutes. The influence of ancillary services will be described in detail in future articles. ●

NOTE: The first article in the series "Planning of Optimal Power Systems" was published in In Detail issue 01, 2007. Please visit www.optimalpowersystems.com for more information.

RETRACTION – IN DETAIL 01, 2007

Fundamentals of power plants

Figure 8 on page 16: The ambient temperature correction factor curves for electrical efficiency for gas turbines and internal combustion engines had changed place by mistake. This is how the correct figure should look:

Thanks go to Sami Myllyviita from Wärtsilä in Finland and Bo Svensson from Diesel & Gas Turbine Worldwide magazine for noticing.

