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A Methodology in Determining the Optimum Mix Generation Units

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Abstract

Due to the introduction of restructured and deregulated electricity market worldwide, many generation units of different technologies compete for electricity demand. Thus, choosing the best mix of power generation to allocate such demands of energy becomes the challenge for the energy practitioners. In this paper the problem of choosing the best source of energy is simulated technically, economically, and financially to come-up with the best mix. The 15 combinations of energy sources were first subjected to technical and economic dispatch. Combinations that passed the technical and economic dispatch were then subjected to financial evaluation using the parameters such as net present value (NPV), internal rate of return (IRR), and payback period. To illustrate the method, 4 generation technologies (coal, biomass, wind, and solar) were simulated for a 200MW base load and an additional 500 MW demand in the next 15 years. Upon the test of the methodology in the generation technologies, a mix of coal and wind sources is the most optimal for the base load of 200 MW, while for the peak load of 700 MW in 15 years, the mix of coal, wind and biomass is the most optimal in both technical, economic, and financial evaluations.

Keywords: economic dispatch, marginal cost, net present value (NPV), internal rate of return (IRR), payback period

1. Introduction

Electrical power systems are going through their first major change in over a hundred years. This change is brought about by the combined forces of new technologies and the restructuring of electrical utilities. Many generation technologies are now being encouraged to participate in the electricity market to compete for such increase in the electricity demand. Such increase in the demand is brought by the advent of industrialization where many industrial firms have been built to cope up with these setting. Thus, putting up of new generating units is a challenge for energy practitioners, and choosing the best energy or energy mix to allocate such demand is the main objective. In this paper, a scenario of additional demand with the given probable generation units is being simulated. It aims to choose the best generation mix to allocate such additional demand. Technical and economic simulations using economic dispatch is used to simulate every scenario of the system to come up with the preliminary ranking of the generation mix. These technically and economically viable mixes are then subjected to financial analysis to come-up with the best mix. Financial parameters such as net present value, internal rate of return, payback period, and the generation rates are used as the benchmark in choosing the best generation mix.

1. *Economic Dispatch*

An economic dispatch calculation (EDC) is performed to dispatch, or schedule, a set of online generating units to collectively produce electricity at a level that satisfies a specified demand in an economical manner (Merev, 2001). The economic dispatch problem is to simultaneously minimize the overall cost rate and meet the load demand of a power system. The power system model consists of *n* generating units already connected to the system. The economic dispatch is to determine the optimal share of load demand for each unit in the range of 3 to 5 minutes (Yalcinoz *et al*., 2001). The economic dispatch problem can be expressed as:

$$\underset{P_i}{\text{Min}} \sum_{i=1}^{n} F_i(P_i) \tag{1}$$

$$F_i(P_i) = (a_i + b_iP_i + c_iP_i^2) \tag{2}$$

where a_i, b_i, and c_i are the cost coefficient of the *i*-th generator and *n* is the number of the generators committed to the operating system. P_i is the power output of the *i*-th generator. The economic dispatch problem subjects to the following constraints:

$$P_{min,\,i} \leq P_i \leq P_{max,\,i} \qquad for\ i = 1,\ \dots\ n \tag{3}$$

$$\sum_{i-1}^{n} \mathrm{P}i - D - L = 0 \tag{4}$$

where

$$L = \sum_{i-1}^{n} B_i\, P_i^2 \tag{5}$$

D is the demand and *L* represents the transmission losses. *B* represents coefficients of transmission losses. $P_{min,i}$ and $P_{max,i}$ are minimum and maximum generation output of the *i*-th generator (Yalcinez *et al*., 2001).

2. Related Economic and Financial Parameters

In what follows, the economic and financial parameters such as marginal cost, net present value (NPV), internal rate of return (IRR), and payback period are discussed.

2.1. Marginal Cost

Marginal costs or incremental costs are defined as the operations and maintenance costs of the most expensive generating plant needed to supply the immediate demand for electricity or it can be also defined as the cost of supplying the last megawatt (MW) of demand. The marginal cost (MC) function is expressed as the derivative of the total cost (TC) function with respect to quantity (Q) (Weber *et al*., 2010).

$$MC = \frac{dTC}{dQ} \tag{6}$$

In the most simple case, the total cost function and its derivative are expressed as follows, where f(Q) is a cost function relating cost to production volume and FC represents fixed costs:

$$\mathrm{TC} = \mathrm{FC} + f(\mathrm{Q}) \tag{7}$$

$$MC = \frac{dTC}{dQ} = \frac{d\,(FT + f\,(Q)\,)}{dQ} = \frac{df\,(Q)}{dQ} \tag{8}$$

Since the fixed costs do not vary with production volume, the marginal cost is not related to fixed costs; the term drops out of the differentiated equation. At each level of production and time period being considered, marginal costs include all costs which vary with the level of production, and other costs are considered fixed costs (Weber *et al*., 2010).

2.2 Net Present Value (NPV)

Net present value (NPV) is a standard method for the financial appraisal of long-term projects. Used for capital budgeting, and widely throughout economics, it measures the excess or shortfall of cash flows, in present value (PV) terms, once financing charges are met (McAfee *et al*., 2006).

The net present value (NPV) of a cash flow stream is the sum of the present values of each of the cash. NPV is given by the expression:

$$\sum_{i=0}^{n} \frac{CF_i}{(1+\mathrm{r})^i} \tag{9}$$

where CF_i is the *net cash flow* in period i (i.e., cash inflow in period i minus cash outflow in period i); r = discount rate; n = number of periods.

NPV is an indicator of how much value an investment or project adds to the value of the firm. The criterion of the NPV method is to consider a project attractive if the NPV of its cash flow stream is positive for a given interest rate. This method is suitable to classify projects, which are mutually exclusive, i.e., once project alternative is carried out, the realization of another alternative is no longer possible. Mutually exclusive project is that when at most one project out of the group can be chosen (McAfee *et al*., 2006). Table 1 shows the various NPV situations.

Table 1. NPV situations

If…	It means…	Then…
NPV > 0	the investment would add value to the firm	the project may be accepted
NPV < 0	the investment would subtract value from the firm	the project should be rejected
NPV = 0	the investment would neither gain nor lose value for the firm	We should be indifferent in the decision whether to accept or reject the project. This project adds no monetary value. Decision should be based on other criteria, e.g. strategic positioning or other factors not explicitly included in the calculation.

2.3 Internal Rate of Return (IRR)

The internal rate of return (IRR) of a cash flow stream is the discount rate, which makes discounted cash inflows equal to discounted cash outflows, i.e., NPV = 0. This means that in case the discount rate is similar to the IRR, the capital invested in a project does not yield any net benefit, but on the other hand no net losses are suffered. A project is a good investment proposition if its IRR is greater than the rate of return that could be earned by alternative investments. Thus, the IRR should be compared to an alternative cost of capital including an appropriate risk premium (McAfee *et al.*, 2006). The IRR is determined with the help of the following expression:

$$\sum_{i=0}^{n} \frac{CFi}{(1+r)^{i}} = 0 \qquad (10)$$

This equation produces values for r that are precisely the internal rates of return of the flow. Alternatively, we could find, by trial and error, i-values for which the NPV is slightly positive and slightly negative, and interpolate linearly between them for i* (IRR) (McAfee *et al.*, 2006).

2.4 Payback Period

The payback period (PBP) is a measure of the time required for an initial investment to be recovered, neglecting the *time value of money*. It is intuitively the measure that describes how long something takes to "pay for itself"; shorter payback periods are obviously preferable to longer payback periods (all else being equal) (McAfee *et al.*, 2006). Thus, if CF_0 represents the initial investment and CF_j is the net cash flow for the *jth* year (j=1, 2, 3,…, n), the payback period satisfies:

$$|CF_0| = \sum_{j=1}^{PBP} CF_j \qquad (11)$$

If the yearly cash net inflows are equal, or if an average value is used, then the above equation would be:

$$PBP = \frac{|CF_0|}{YCF} \qquad (12)$$

Where *YCF* represents the (average) yearly cash flow; *PBP* is the payback period. With this method, the criterion is that the project with the lowest pay-back period would be preferred than others (McAfee *et al.*, 2006).

3. Choosing the Best Mix

In this section, a scenario of increasing demand is presented and the process of how to choose the best generation mix to supply the base and peak demand of the system is shown. The process of choosing the best mix of generation is done by subjecting all the possible mix cases into technical, economic, and financial analysis. Subjecting these cases into these stages will give a favorable result to both the consumers and investors.

3.1 The Scenario

At present, a certain system is having a robust growth in energy demand. Intention among power producers suggests that there is a need to increase existing supply of power for the next 15 years. Some big power generators have already expressed their desire to increase supply by expanding present capacities. The following are figure of merits in investing for additional energy generations:

Clean coal fluidized bed plants:
Supply: 100 – 500 MW; investment cost: 0.35M$/Mwatt of installed plant; maintenance cost: 5 % of investment cost/ year; lifespan: 40 years
Cost function: $C_cP_c = 0.015\ P_c^2 + 16.395P_\mathrm{c} + 4.5$

Wind energy plant:
Supply: 10 – 200 MW; investment cost: 1.6M$/Mwatt of installed plant; maintenance cost: 1.5% of investment cost/ year; lifespan: 30 years
Cost function:

Table 2. Wind energy cost function (Navigant Consulting, 2007)

MW supply	Cost ($/MWh)	MW supply	Cost ($/MWh)
10	40.11	110	56.12
20	42.25	120	57.89
30	43.18	130	60.59
40	44.60	140	62.77
50	46.51	150	64.40
60	48.03	160	65.22
70	49.52	170	66.55
80	50.74	180	67.61
90	52.76	190	68.67
100	53.99	200	69.89

Solar energy plant:
Supply: 10 – 100 MW; investment cost: 6M$/Mwatt peak; maintenance cost: 0.2% of investment cost/ year; lifespan: 30 years
Cost function:

Table 3. Solar energy cost function (Navigant Consulting, 2007)

MW supply	Cost ($/MWh)	MW supply	Cost ($/MWh)
10	202.21	60	254.16
15	208.72	65	264.64
20	214.27	70	268.60
25	218.16	75	274.68
30	223.46	80	281.38
35	225.74	85	283.74
40	231.96	90	287.15
45	237.38	95	292.04
50	242.11	100	299.14
55	250.38		

Biomass energy plant:
Supply: 100 – 300 MW; investment cost: 2.75M$/Mwatt of installed plant; maintenance cost: 5% of investment cost/ year; lifespan: 25 years
Cost function:

Table 4. Biomass energy cost function (Navigant Consulting, 2007)

MW supply	Cost ($/MWh)	MW supply	Cost ($/MWh)
100	70.08	210	76.65
110	70.77	220	77.30
120	71.27	230	77.66
130	71.80	240	78.58
140	72.34	250	79.13
150	72.84	260	79.55
160	73.36	270	80.21
170	74.03	280	80.93
180	74.72	290	81.58
190	75.58	300	82.32
200	76.03		

Assuming that there is a base load of 200 MW and in the 15 years a 500 MW additional load is needed in the system, choose the best energy generation unit or generation mix to allocate the demands.

3.2 Technical Analysis (Optimal Power Flow and Economic Dispatch)

Possible combinations of energy sources mentioned previously are then subjected to technical analysis using the economic dispatch. The base and peak load scenarios are simulated with the different combinations or mix of the energy sources and rank in accordance with the marginal cost and technical loss of the system. The energy sources possible mix are grouped for one source, two sources, three sources, and four sources to supply the base and peak demand.

3.2.1 Base Load

Figure 1 is the scenario for the base load of 200MW of the system. This scenario is then subjected to the possible mix of generation technologies to supply the 200MW demand and the results of each mixes are tabulated and ranked in Table 5.

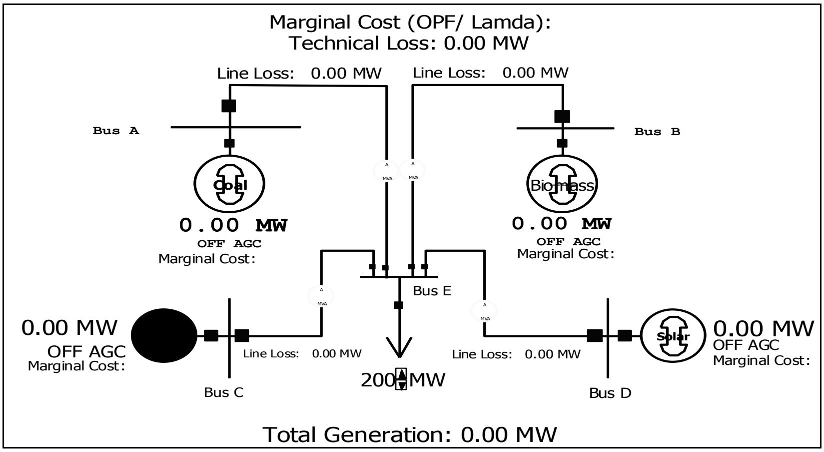

Figure 1. Base load scenario

Table 5 and Figure 2 show that the coal and biomass mix is ranked number 1 due to their low incremental cost and technical loss, followed by coal, wind, and solar; coal and wind; coal and solar; coal only; biomass, wind, and solar; biomass and wind; biomass and solar; wind and solar; and lastly the biomass only. Other remaining cases do not satisfy the required 200MW demand.

Table 5. Summary of technical, economic evaluation, and technical ranking (base load)

Source	Combination/s	Generation (MW)	Marginal cost ($/MWh)	Line loss generation to load (MW)	System technical loss (MW)	Total generation (MW)	Incremental cost (Lambda) ($/MWh)	Incremental cost (Lambda) ($kWh)	Rank
1	Coal only	201.37	25.44	1.37	1.37	201.37	25.44	0.02544	4
	Biomass only	201.37	76.03	1.37	1.37	201.37	76.03	0.07603	9
	Wind only	201.37	69.89	1.37	1.37	201.37	5, 000.00	5.00	
	Solar only	201.37	200.14	1.37	1.37	201.37	5, 000.00	5.00	
2	Coal	191.28	25.13	1.25	1.28	201.28	25.13	0.02513	3
	Wind	10	40.11	0.02					
	Coal	100.68	22.42	0.34	0.68	200.68	22.42	0.022242	1
	Biomass	100	70.08	0.34					
	Coal	191.28	25.13	1.25	1.28	201.28	25.13	0.02513	3
	Solar	10	202.21	0.02					
	Biomass	100.02	70.08	0.34	0.68	200.68	53.99	0.05399	6
	Wind	100.66	53.99	0.34					
	Biomass	191.28	75.58	1.25	1.28	201.28	75.58	0.07558	7
	Solar	10	202.21	0.02					
	Wind	191.28	68.67	1.25	1.28	201.28	68.67	0.06867	8
	Solar	10	202.21	0.02					
3	Coal	90.63	22.11	0.28	0.63	200.63	-5, 000.00	-5.00	
	Biomass	100	70.08	0.34					
	Wind	10	40.11	0.01					
	Coal	90.63	22.11	0.28	0.63	200.63	-5, 000.00	-5.00	
	Biomass	100	70.08	0.34					
	Solar	10	202.21	0.01					
	Coal	181.16	24.63	1.41	1.16	201.16	24.83	0.02483	2
	Wind	10	40.11	0.01					
	Solar	10	202.21	0.01					
4	Biomass	100	70.08	0.34	0.63	200.63	52.76	0.05276	5
	Wind	90.63	52.76	0.29					
	Solar	10	202.21	0.01					
	Coal	80.58	21.81	0.22	0.71	200.58	-5, 000.00	-5.00	
	Biomass	100	70.08	0.34					
	Wind	10	40.11	0.01					
	Solar	10	202.11	0.01					

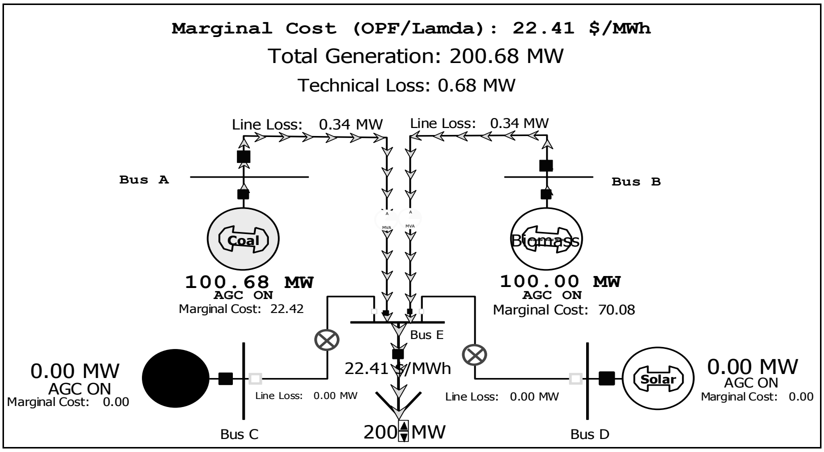

Figure 2. Rank 1 base load scenario

3.2.2 Peak Load

Figure 3 shows the scenario for the peak load of 700MW of the system. This scenario is then subjected to different mixes of generation technologies to supply the 700MW demand and the results of each mixes are tabulated and ranked in Table 6.

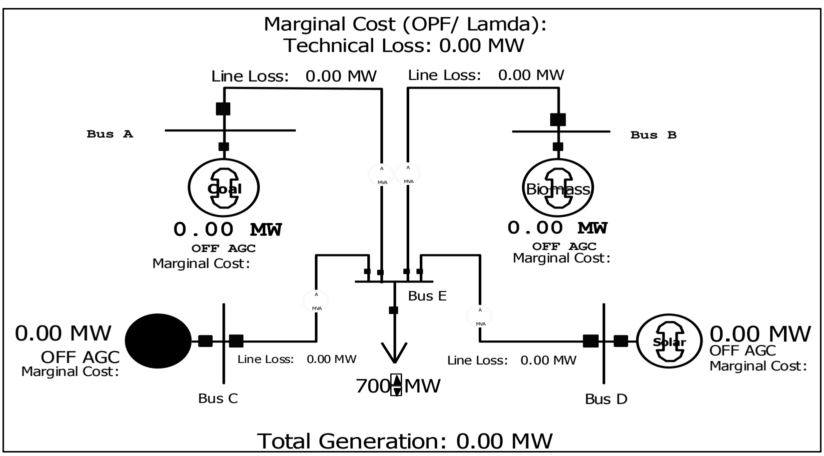

Figure 3. Peak load scenario

Table 6 and Figure 4 show that coal, biomass, wind and solar mix is ranked number 1 due to their low incremental cost and technical loss, followed by the coal, biomass, and wind; coal, wind, and solar; coal and biomass; and lastly coal and biomass mix. Other remaining cases do not satisfy the required 700MW demand.

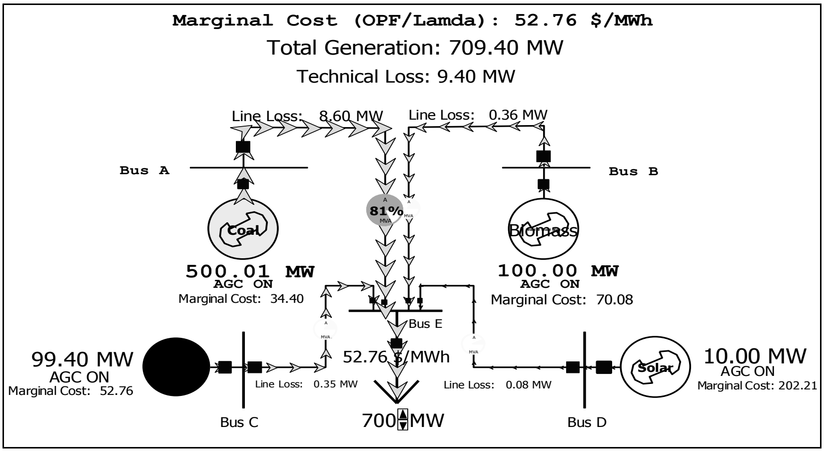

Figure 4. Rank 1 peak load scenario

3.3 Financial Analysis

After subjecting the base and peak load scenarios in terms of technical and economic analysis, financial analysis are undertaken for each scenario for second preliminary ranking of the best generation mix. Financial parameters such as the net present value (NPV), investment rate of return (IRR), and payback period were used in ranking best mix which can be advantageous to consumers as well as to investors. In the process of calculating the said parameters, calculation of the annual cost of project, maintenance cost, depreciation cost, annualized sales, and projected project cost (investment) are done for every scenario and results are presented in Table 7, 6, 9 and 10. Annual sales and investment can be calculated using:

$$AS = PS * C * 350 * 24 \tag{13}$$

$$I = IM * PC \tag{14}$$

where AS = Annual sales ($); PS = Plant supply (MW); PC = Plant capacity (MW); C = Marginal cost per kwh ($/kWh); I = Projected project cost or investment ($); IM = Investment cost per MW ($/MW)

Other parameters such as maintenance cost and depreciation cost are calculated as a percentage of the annual investment for the different technologies. Also a discount rate of 10% was used as an ideal discount rate.

Table 6. Summary of technical, economic evaluation, and technical ranking (peak load)

Source	Combination/s	Generation (MW)	Marginal cost ($/MWh)	Line loss generation to load (MW)	System technical loss (MW)	Total generation (MW)	Incremental cost (Lambda) ($/MWh)	Incremental cost (Lambda) ($kWh)	Rank
1	Coal only Biomass only Wind only Solar only	Unable to supply demand							
2	Coal	510.24	34.7	8.81	10.25	710.24	5, 000.00	5.00	0
	Wind	200	69.89	1.44					
	Coal	500.02	34.4	8.53	10.02	710.02	76.03	0.07603	4
	Biomass	210	76.03	1.36					
	Coal	613.31	37.79	12.75	13.31	713.31	5, 000.00	5.00	
	Solar	100	299.14	0.56					
	Biomass	510.24	82.32	8.81	10.25	710.24	5, 000.00	5.00	
	Wind	200	69.89	1.44					
	Biomass	613.31	82.32	12.75	13.31	713.31	5, 000.00	5.00	
	Solar	100	299.14	0.56					
	Wind	613.31	69.89	12.75	13.31	713.31	5, 000.00	5.00	
	Solar	100	299.14	0.56					
3	Coal	500	34.39	8.53					
	Biomass	100	70.08	0.4	9.39	709.39	53.99	0.05399	2
	Wind	109.39	53.99	0.46					
	Coal	499.99	34.39	8.53					
	Biomass	200.06	76.03	1.36	10.04	710.05	76.03	0.07603	5
	Solar	10	202.21	0.15					
	Coal	500.05	34.4	8.53					
	Wind	200	69.89	1.36	10.05	710.05	68.67	0.06867	3
	Solar	10	202.21	0.15					
	Biomass	407.39	82.32	5.64					
	Wind	200	69.89	1.36	7.4	707.39	5, 000.00	5.00	
	Solar	100	299.14	0.39					
4	Coal	500	34.4	8.6					
	Biomass	100	70.08	0.36	9.4	709.4	52.76	0.05276	1
	Wind	99.4	52.76	0.35					
	Solar	10	202.11	0.08					

Table 7 shows the preliminary calculations for the financial evaluation computations in the base load scenario. Then after computing these important parameters, the financial parameters (NPV, IRR, and payback period) are also calculated and the results are tabulated and ranked in Table 8. NPV, IRR, and payback period are computed using the annual energy sales of the projects minus the cost and maintenance of the projects until the end of its life.

Table 8 shows that after calculating all financial parameters coal and wind mixed of generation units is the best combination that satisfies the financial evaluation for a 200MW demand, and followed by generating alone the Coal generation unit.

Tables 9 and 10 are preliminary calculations for the financial evaluation computations in the peak load scenario.

Table 11 shows the calculated NPV, IRR, and payback period with the corresponding rank of generation mix. Based on the results, the coal, wind, and biomass combination has the least generation rate and most favorable financial parameters (NPV, IRR, and payback period), hence, it is ranked number 1 to supply the peak load of 700MW. This mix is followed by the coal - biomass combination and coal – biomass - solar combination, which also have lower generation rate and favorable financial parameters.

Table 7. Preliminary calculation (base load 200 MW)

Inputs	Coal only	Coal + Wind		Coal + Biomass		Coal + Solar		Coal + Wind + Solar		
	Coal	Coal	Wind	Coal	Biomass	Coal	Solar	Coal	Wind	Solar
Plant capacity (MW)	100 – 500	100 – 500	10 – 200	100 – 500	100 – 300	100 – 500	10 – 100	100 – 500	10 – 200	10 – 100
Cost per kWh ($/kWh)	0.02544	0.02513	0.02513	0.02242	0.02242	0.02513	0.02513	0.02483	0.02483	0.02483
Plant supply (Mwatt)	201.37	191.28	10	100.68	100	191.28	10	181.16	10	10
Projected project cost (investment)	70,479,500	66,948,000	16,000,000	35,238,000	275,000,000	66,948,000	60,000,000	63,406,000	16,000,000	60,000,000
Coal cost	350,000	350,000		350,000		350,000		350,000		
Wind cost			1,600,000						1,600,000	
Solar cost							6,000,000			6,000,000
Biomass cost					2,750,000					
Investment cost per Mwatt	350,000	350,000	1,600,000	350,000	2,750,000	350,000	6,000,000	350,000	1,600,000	6,000,000
Discount rate	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Projected life	40	40	30	40	25	40	30	40	30	30
Depreciation	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Maintainance	5.00%	5.00%	1.50%	5.00%	5.00%	5.00%	0.20%	5.00%	1.50%	0.20%
Outputs										
Annual cost of project	7,207,192.40	6,846,063.28	1,697,267.97	3,603,417.25	30,296,219.85	6,846,063.28	6,364,754.90	6,483,860.43	1,697,267.97	6,364,754.90
Depreciation cost	216,215.77	205,381.90	50,918.04	108,102.52	908,886.60	205,381.90	190,942.65	194,515.81	50,918.04	190,942.65
Maintenance cost	360,359.62	342,303.16	25,459.02	180,170.86	1,514,810.99	342,303.16	12,729.51	324,193.02	25,459.02	12,729.51
Annualized sales	43,031,963.52	40,377,677.76	2,110,920.00	18,960,863.04	18,832,800	40,377,677.76	2,110,920.00	37,784,903.52	2,085,720.00	2,085,720.00

Table 8. Financial ranking (base load)

Combinations	Generation rate	Annual net revenue	NPV	IRR	Payback period (years)	Rank
Coal only	0.02544	42,671,604	315,280,253.43	60.54%	1.65	2
Coal	0.02513	40,035,375	295,054,507.92	59.80%	1.67	1
Wind	0.02513	2,085,461	3,326,783.90	12.67%	7.67	
Coal	0.02242	18,780,692	134,926,673.94	53.30%	1.88	
Biomass	0.02242	17,317,989	107,094,473.40	3.85%	15.88	
Coal	0.02513	40,035,375	295,054,507.92	59.80%	1.67	
Solar	0.02513	2,098,190	36,564,125.19	0.31%	28.60	
Coal	0.02483	37,460,710	275,385,625.38	59.08%	1.69	

Table 9. Preliminary calculation 1 (peak load 700MW)

Inputs	Coal + Biomass		Coal + Biomass + Solar			Coal + Wind + Solar		
	Coal	Biomass	Coal	Biomass	Solar	Coal	Wind	Solar
Plant capacity (MW)	100 - 500	100 - 300	100 - 500	100 - 300	10 - 100	100 - 500	10 - 200	10 - 100
Cost per kWh ($/kWh)	0.07603	0.07603	0.07603	0.07603	0.07603	0.06867	0.06867	0.06867
Plant supply (Mwatt)	499.99	200	499.99	200.06	10	500.05	200.00	10.00
Projected project cost (investment)	174,996,500	550,165,000	174,996,500	550,165,000	60,000,000	175,017,500	320,000,000	60,000,000
Coal cost	350,000		350,000			350,000		
Wind cost							1,600,000	
Solar cost					6,000,000			6,000,000
Biomass cost		2,750,000		2,750,000				
Investment cost per Mwatt	350,000	2,750,000	350,000	2,750,000	6,000,000	350,000	1,600,000	6,000,000
Discount rate	10%	10%	10%	10%	10%	10%	10%	10%
Projected years of operation	40	25	40	25	30	40	30	30
Depreciation	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Maintainance	5.00%	5.00%	5.00%	5.00%	0.20%	5.00%	1.50%	0.20%
Outputs								
Annual cost of project	17,895,039.61	60,610,617.44	17,895,039.61	60,610,617.44	6,364,754.90	17,897,187.06	33,945,359.44	6,364,754.90
Depreciation cost	536,851.19	1,818,318.52	536,851.19	1,818,318.52	190,942.65	536,915.61	1,018,360.78	190,942.65
Maintenance cost	894,751.98	3,030,530.87	894,751.98	3,030,530.87	12,729.51	894,859.35	509,180.39	12,729.51
Annualized sales	319,319,613.48	127,768,719.12	319,319,613.48	127,768,719.12	6,386,520	288,442,841	115,365,600	5,768,280

Table 10. Preliminary calculation 1 (peak load)

Inputs	Coal + Wind + Biomass			Coal + Wind + Solar + Biomass			
	Coal	Wind	Biomass	Coal	Wind	Solar	Biomass
Plant capacity (MW)	100 - 500	10 - 200	100 - 300	100 - 500	10 - 200	10 - 100	100 - 300
Cost per kWh ($/kWh)	0.05399	0.05399	0.05399	0.05276	0.05276	0.05276	0.05276
Plant supply (Mwatt)	500	109.39	100	500	99.4	10	100
Projected project cost (investment)	175,000,000	175,024,000	275,000,000	175,000,000	159,040,000	60,000,000	275,000,000
Coal cost	350,000			350,000			
Wind cost		1,600,000			1,600,000		
Solar cost						6,000,000	
Biomass cost			2,750,000				2,750,000
Investment cost per Mwatt	350,000	1,600,000	2,750,000	350,000	1,600,000	6,000,000	2,750,000
Discount rate	10%	10%	10%	10%	10%	10%	10%
Projected years of operation	40	30	25	40	30	30	25
Depreciation	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Maintainance	5.00%	1.50%	5.00%	5.00%	1.50%	0.20%	5.00%
Outputs							
Annual cost of project	17,895,397.52	18,566,414.35	30,296,219.85	17,895,397.52	16,870,843.64	6,364,754.90	30,296,219.85
Depreciation cost	536,861.93	556,992.43	908,886.60	536,861.93	506,125.31	190,942.65	908,886.60
Maintenance cost	894,769.88	278,496.22	1,514,810.99	894,769.88	253,062.65	12,729.51	1,514,810.99
Annualized sales	226,758,000	49,610,115.24	45,351,600	221,592,000	44,052,489.60	4,431,840	44,318,400

Table 11. Financial ranking (peak load)

Combinations	Generation rate	Annual net revenue	NPV	IRR (%)	Payback period (years)	Rank
Coal	0.05276	220,697,230	1,802,917,642.55	126.11	0.79	
Wind	0.05276	43,799,427	230,775,865.02	27.52	3.63	
Solar	0.05276	4,419,110	(16,674,021.26)	6.13	13.58	
Biomass	0.05276	42,803,589	103,208,991.22	15.10	6.42	
Coal	0.07603	318,443,967	2,671,884,279.94	181.96	0.55	2
Biomass	0.07603	130,935,817	555,463,318.15	22.53	4.41	
Coal	0.05399	225,863,230	1,848,843,620.75	129.06	0.77	
Wind	0.05399	43,799,427	263,655,411.88	28.17	3.55	1
Biomass	0.05399	43,836,789	111,734,807.36	15.51	6.27	
Coal	0.07603	318,424,861	2,671,723,973.30	181.96	0.55	
Biomass	0.07603	124,738,188	529,171,387.75	22.53	4.41	3
Solar	0.07603	6,373,790	77,434.35	10.02	9.41	
Coal	0.06867	287,547,982	2,397,208,000.39	164.30	0.61	
Wind	0.06867	114,856,420	693,401,494.21	35.89	2.79	
Solar	0.06867	5,755,550	(5,220,834.38)	8.84	10.42	

4. Results and Discussion

After the technical, economic, and financial analysis have been conducted, final ranking of the different mixes is determined in terms of technical viability and financial evaluation ranking. In this way, the mix considered for the demand shall be favorable to both the consumers and investors.

Table 12 shows that after the preliminary analysis and rankings for the best mix at the base load of 200 MW, the best mix that is favorable to both the consumers and investors is coal and wind mix of generation units. It is therefore clear that for the tested five-bus system under a deregulated electricity market, the best mix to dispatch and to consider during base loads is the combination of the coal and wind generation units.

Table 12. Base load final ranking

Combinations	Technical and economic evaluation ranking	Financial evaluation ranking	Final ranking
Coal only	4	2	2
Coal Wind	3	1	1
Coal Biomass	1		
Coal Solar	3		
Coal Wind Solar	2		

Table 13 shows the final ranking of generation mix for peak load of 700MW. It can be seen from the table that the best generation mix which should be considered is the combination of the coal, wind, and biomass generation Units due to its high ranks in the preliminary ranking. With these results it is clear that during peak loads on the 5 bus test system under a deregulated electricity market, it is more advantageous to consider the mix of coal, wind, and biomass generation units since it is favorable to both the consumers and the investors. The consumers will have a much lower generation rates, while the investors will not be losing on the production of the needed power, thus, everyone benefits from it.

Table 13. Peak load final ranking

Combinations	Technical and economic evaluation ranking	Financial evaluation ranking	Final ranking
Coal Wind Solar Biomass	1		
Coal Biomass	4	2	2
Coal Wind Biomass	2	1	1
Coal Biomass Solar	5	3	3
Coal Wind Solar	3		

Moreover, it is therefore proven that having such new methodology in determining the best mix will definitely give viable results. It will give both the consumers and the investors a clearer picture of the characteristic of the system technically, economically, and financially. This proposed method in determining the optimal mix for demands may be applicable in larger application like the Mindanao Grid. It is therefore recommended to apply the said methods in the Mindanao Grid to further test for its viability and for further improvement of the steps in this proposed process.

5. References

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