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Quantifying energy not served in power capacity expansion planning with intermittent sustainable technologies

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Abstract

In this work, estimations are made of the energy not served (ENS) in a power capacity expansion problem in the case of integration of intermittent sustainable technologies. For this purpose, part of the power generation system of the United Arab Emirates (UAE) is examined. Five capacity expansion scenarios using sustainable power generation technologies are investigated, including the integration of carbon capture and storage (CCS) technologies and solar-based power generation systems (intermittent systems as well as dispatchable systems using thermal storage), and compared with the business as usual scenario (BAU) for various natural gas prices. Based on the input data and assumptions made, the results indicate that the BAU scenario is the least cost option. However, if the UAE move towards the use of sustainable power generation technologies in order to reduce carbon dioxide emissions, the most suitable alternative technologies are: (i) natural gas combined cycle technology integrated with CCS systems, and (ii) concentrated solar power systems with 24/7 operation. The other candidate sustainable technologies have a considerable adverse impact on system reliability since their dispatchability is marginal, leading to power interruptions and thus high ENS cost.

Keywords: Energy not served, Power system reliability, Power economics, Generation expansion planning, Cost of electricity

1. Introduction

In a power capacity expansion problem the annual capacity reserve margin is determined as the level of additional standby power required being readily available during peak demand in order to cover, for example, the possibilities of a generator unit failure or a sudden surge in demand due to unusually high temperatures. In mathematical terms the capacity reserve margin is the measurement of the capacity to generate more power than the system generally requires at peak usage, or the amount of unused power available when the system is at peak usage. The annual capacity reserve margin, CRM, is defined as:

$$CRM = \frac{P_{in} - P_m}{P_m}, \tag{1}$$

where P_{in} is the installed firm capacity (secure available capacity or dispatchable capacity) in MWe and P_m is the system peak load in MWe which can be either measured or projected. The installed firm capacity, P_{in}, can be determined by the addition of the installed capacity of all dispatchable (firm capacity) power generation units present in a power system. If an expansion plan contains system configurations for which the annual energy demand E_t, in kWh, is greater than the expected annual generation G_t, in kWh, of all units existing in the configuration for the corresponding year t, the total costs of the plan are penalized by the resulting cost of the energy not served (ENS). This cost is a function of the amount of ENS, N_t, in kWh, which is calculated by:

$$N_t = E_t - G_t. \tag{2}$$

In this work, estimations are made of ENS in a power

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capacity expansion problem in the case of integration of intermittent sustainable technologies. As a test case the power generation system of the Emirate of Sharjah in the United Arab Emirates (UAE) will be examined. In particular, a range of candidate sustainable power technologies are integrated within the existing power generation system of the Emirate of Sharjah [1] and the total annual power generation cost and the related energy not served is calculated. Five scenarios using sustainable power generation technologies are investigated, including the integration of carbon capture and storage (CCS) technologies and solar-based power generation systems (both intermittent systems as well as dispatchable systems using thermal storage), and compared with the business as usual (BAU) scenario for different natural gas prices. For the simulations, the WASP IV [2] software package is employed, which is a specialized simulation software used widely for the selection of the optimum expansion planning of a generation system. The electricity unit cost of the power generation system and the related ENS for the various investigated scenarios can then be calculated.

In section 2, the test case power generation system and the simulation software used are presented. In section 3 the data and assumptions used for the optimization analysis are discussed. In section 4 the results obtained for the optimum expansion of the Emirate of Sharjah power generation system are presented in detail. The conclusions are summarized in section 5.

2. Test case description and optimization

In this investigation, estimations are made of ENS resulting from large-scale integration of sustainable technologies, with the Emirate of Sharjah being examined as a test case. The electricity sector in the Emirate of Sharjah is monopolistic, and the owner and operator of the power stations is the state-owned company Sharjah Electricity and Water Authority (SEWA). There are seven power stations in the Emirate of Sharjah. The total installed capacity in the Emirate of Sharjah is 2576.5 MWe with an annual electricity generation of approximately 10 TWh [3].

The future generation system of the Emirate of Sharjah power industry is simulated using the Wien Automatic System Planning IV package (WASP IV), which is widely used for automatic generation planning [2]. The WASP IV software package finds the optimal expansion plan for a given power generating system over a period of up to 30 years [4]. The predicted seasonal load duration curves, the efficiency, the maintenance period and the forced outage rate of each generating plant are taken into account. The objective function, which shows the overall cost of the generation system (existing and candidate generating plants), is composed of several components. The components, related to the candidate generating units, are the capital cost and the salvage capital cost. The components, which are related to both the existing and candidate generating units, are the fuel cost and the fixed operation and maintenance costs. The cost to the national economy of the ENS because of shortage of capacity or interruptions is also taken into consideration.

WASP IV compares the total costs for the whole generation system for a number of candidate units. In the production simulation of WASP, a one-year period is divided into, at most, 12 sub-periods for each of which a probabilistic simulation is applied. Equivalent load duration curves in the probabilistic simulation are approximated using Fourier series. The Fourier expansion makes it computationally simple to convolve and deconvolve generating units in the probabilistic simulation. The decision of the optimum expansion plan is made by the use of forward dynamic programming. The number of units for each candidate plant type that may be selected each year, in addition to other practical factors that may constrain the solution, is specified. If the solution is limited by any such constraints, the input parameters can be adjusted and the model re-run. The dynamic programming optimization is repeated until the optimum solution is found.

Each possible sequence of power units added to the system (expansion plan) meeting the constraints is evaluated by means of a cost function (the objective function), which is composed of (a) capital investment costs, I, (b) salvage value of investment costs, S, (c) fuel costs, F, (d) non-fuel operation and maintenance costs, M, and (e) cost of ENS, Φ. Thus,

$$B_j = \sum_{t=1}^{T} \left(I_{jt} - S_{jt} + F_{jt} + M_{jt} + \Phi_{jt} \right), \qquad (3)$$

where, B_j is the objective function attached to the expansion plan j, t is the time in years $(1, 2, \ldots, T)$ and T is the length of the study period (total number of years) in US$. All costs are discounted to a reference date at a given discount rate. The optimum expansion plan is the min B_j among all j.

3. Data and assumptions

In this capacity expansion analysis future sustainable generation technologies are integrated for future expansion within the existing power generation system of the

Emirate of Sharjah [3]. In particular two CCS technologies, namely post-combustion and pre-combustion CCS, integrated to the natural gas combined cycle technology [5] are investigated as well as two solar-based renewable energy sources for power generation (RES-E), such as, large PV parks [6] and parabolic trough CSP [4] systems. For the purposes of this work, the parabolic trough CSP technology is chosen mainly due to its technological maturity [7]. The study horizon covers a period of 30 years with a maximum annual capacity reserve margin of 20% and an assumed discount rate of 6%. For the simulations we employ the WASP IV software package [2] with all costs updated to 2013 values.

In addition to the business as usual (BAU) scenario for the future expansion of the Emirate of Sharjah power generation system, which considers the natural gas turbine plants as the only candidate option, five more scenarios are examined in the analysis in order to assess the electricity unit cost of the future power generation system with the expected penetration of CCS integration and solar-based RES-E technologies. Therefore, all the scenarios examined in this work are listed below:

1. Expansion with gas turbine technologies of 110 MWe capacity using natural gas, which is considered as the BAU scenario,
2. Expansion with natural gas combined cycle technologies of 250 MWe capacity, integrated with a pre-combustion CCS systems,
3. Expansion with natural gas combined cycle technologies of 250 MWe capacity, integrated with a post-combustion CCS systems,
4. Expansion with PV parks of 50 MWp capacity,
5. Expansion with parabolic trough CSP technologies of 50 MWe capacity with no thermal storage,
6. Expansion with parabolic trough CSP technologies of 50 MWe capacity with 24/7 operation.

In order to examine the effect of natural gas price on the optimum generation planning, except for the base case natural gas price of 4 US$/MMBtu, a sensitivity analysis has been, also, carried out with natural gas prices of 6 US$/MMBtu, 8 US$/MMBtu and 10 US$/MMBtu.

The technical and economic data of the candidate technologies used as an input to WASP IV are tabulated in Table 1 and Table 2 respectively.

For the purposes of this analysis a number of technical factors inherent in the processes of CCS technology that contribute to overall plant efficiency penalization have been accounted for by the reduced efficiency used [8]. Also, the natural gas combined cycle plants with post-combustion CCS integration employ a monoethanolamine based system. The CO_2 transport and geologic storage costs [9] are not examined in this study, since these have not yet been determined in the case of the Emirate of Sharjah. Obviously, the lack of concrete information aiding the definition of these costs is a serious concern, because unless the exact storage and transportation cost is determined, decisions regarding the feasibility of CCS technologies cannot be fully justified [10].

In the case of the PV technology, with a capacity of 50 MWp, a typical mono-Si solar PV module has been selected [11] with a capacity of 185 W, efficiency 14.2% and area of 1.3 m^2. As the solar potential varies with the orientation and the inclination of the solar PV panels [12], a south orientation at the yearly average optimum fixed angle of 24 degrees is assumed [1]. In the case of parabolic trough CSP technology, with a capacity of 50 MW, we assume a typical solar to electricity efficiency of 15%. The effect of two-tank molten salt thermal storage integration is examined in this analysis in the case of scenario (f)—thermal storage 24 h/day (24/7 operation). This option is not currently available commercially [13], since the major obstacles to be overcome are size, operational issues and the cost of the storage tanks required for thermal storage. Extensive research and development is currently underway using various storage mediums that can enable this technology to materialize in an economically viable way [14]. The integration of a thermal storage system has a direct effect on (a) capital cost (a greater solar field is necessary), (b) land area (more space is needed to accommodate the greater solar field) and (c) electricity production (power production is increased due to increased operating hours) [4].

4. Discussion of the results

As mentioned in section 1 the capacity reserve margin is a function of the installed firm capacity, P_{in}, which can be determined by the addition of the installed capacity of all dispatchable (firm capacity) power generation units present in a power system. The candidate options in this investigation of the gas turbine technology and the combined cycle technology integrated with CCS are both dispatchable technologies. In contrast, dispatchability of RES-E is marginal, depending on the type of technology. However, CSP plants when integrated with thermal energy storage system can provide 100% firm capacity (secure available capacity). This is well justified and supported in the literature [13, 15–18]. CSP is unique among RES-E

Table 1: Technical data of candidate technologies

Option no.	Candidate technology	Fuel type	Maximum net load, MWe	Minimum operating load, MWe	Heat rate at maximum load, kJ/kWh	Heat rate at minimum load, kJ/kWh	Average incremental heat rate, kJ/kWh	Forced outage rate, %	Yearly scheduled maintenance, days
a	Gas turbine (BAU)	Natural gas	110	10	11,500	24,200	10,200	0.5	15
b	Combined cycle with a pre-combustion CCS	Natural gas	250	80	8,540	8,930	8,350	6.0	30
c	Combined cycle with a post-combustion CCS	Natural gas	250	80	8,940	9,380	8,370	10.0	30
d	PV park	–	50	50	–	–	–	80.1	4
e	Parabolic trough CSP with no thermal storage	–	50	50	–	–	–	91.2	40
i	Parabolic trough CSP with 24/7 operation	–	50	25	–	–	–	24.9	40

Table 2: Economic data of candidate technologies

Option no.	Candidate technology	Fuel type	Capacity, MWe	Capital cost, US$/kW	Fuel net calorific value, GJ/t	Fuel cost, US$/MMBtu	Fixed O&M, US$/kW/month	Variable O&M, US$/kW/month
a	Gas turbine (BAU)	Natural gas	110	1,000	45	4/6/8/10	2.6	2.60
b	Combined cycle with a pre-combustion CCS	Natural gas	250	1,250	45	4/6/8/10	3.1	3.24
c	Combined cycle with a post-combustion CCS	Natural gas	250	1,380	45	4/6/8/10	8.7	11.50
d	PV park	-	50	2,000	–	–	43	0.10
e	Parabolic trough CSP with no thermal storage	-	50	5,000	–	–	83	0.70
i	Parabolic trough CSP with 24/7 operation	-	50	7,640	–	–	83	0.70

technologies in that it is variable like solar and wind, but can easily be coupled with thermal energy storage system, making it highly dispatchable [15]. In [16] it is stated that CSP integrated with a thermal energy storage system is a very promising RES-E technology and has the potential to replace base load generation. Also, optimization models developed for the integration of RES-E in power systems indicated that a dispatchable CSP system utilizes thermal energy storage system to provide firm (i.e., dispatchable) capacity [17]. CSP plants with thermal energy storage are dispatchable, thus the capacity value of the plant is equal to the capacity factor during the summer peak load period, which is essentially the nameplate capacity [18]. By careful sizing of the CSP plant integrated with a thermal energy storage system, it is feasible to build a power station that provides power day and night, 24/7 [13].

For interconnected systems energy regulatory bodies usually require that a capacity reserve margin of 10%–20% be maintained as insurance against breakdowns in part of the system or sudden increases in energy demand. In the case of the Emirate of Sharjah a capacity reserve margin between the lower and upper limits of 10% and 20% is taken into consideration, since interconnections exist with other Emirates within the UAE. In the case of dispatchable power generation technologies the capacity reserve margin lies within the lower and upper limits justifying high reliability during the operation of the power system. When the candidate technologies for the expansion of the power system are either a CSP system with no thermal energy storage or a PV system, the reliability is very low. The effect of low reliability on the economics of the power generation system, i.e. the cost of ENS, is examined below.

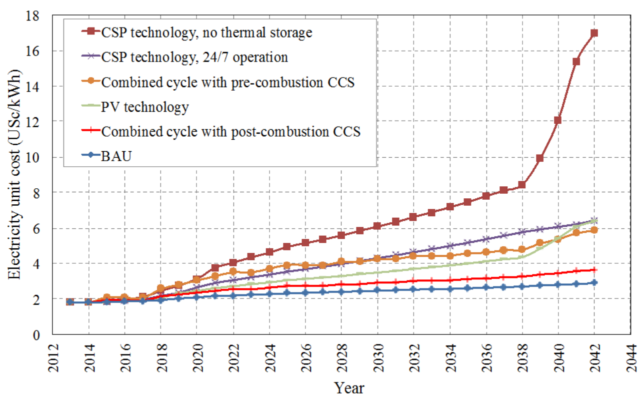

Figure 1: Generation system annual electricity unit cost in real prices (base case scenario, natural gas price 4 US$/MMBtu)

The expected annual electricity unit cost (excluding the cost of ENS) for different natural gas prices are illustrated in Fig. 1–Fig. 4. We observe that in all cases the least cost option is the BAU scenario followed by the combined cycle integrated with a pre-combustion CCS system scenario.

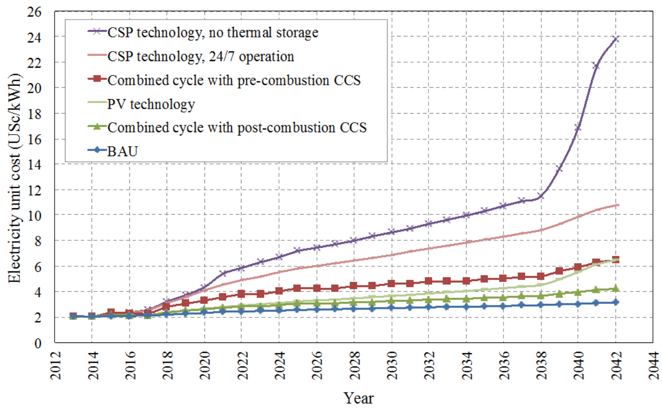

Figure 2: Generation system annual electricity unit cost in real prices (sensitivity analysis for natural gas price of 6 US$/MMBTU)

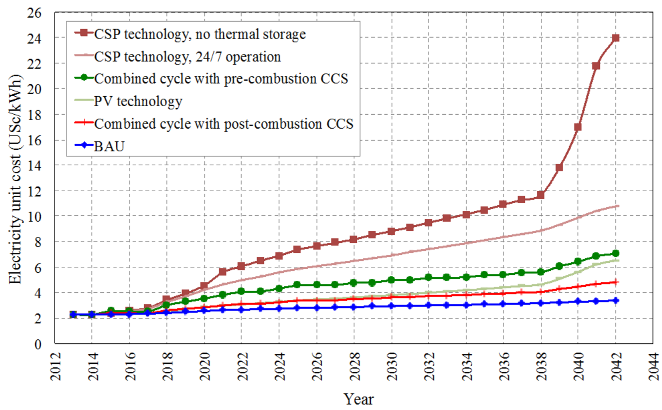

Figure 3: Generation system annual electricity unit cost in real prices (sensitivity analysis for natural gas price of 8 US$/MMBTU)

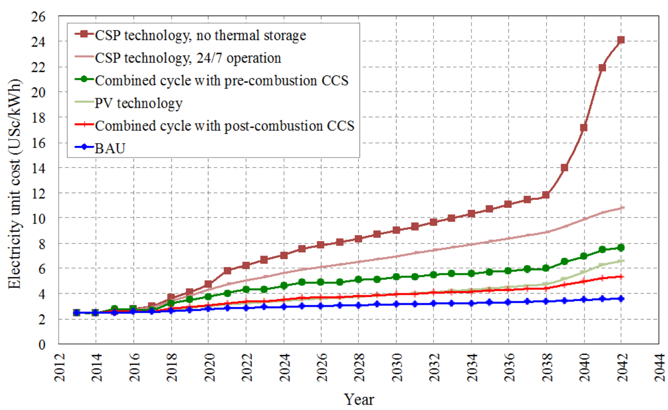

Figure 4: Generation system annual electricity unit cost in real prices (sensitivity analysis for natural gas price of 10 US$/MMBTU)

Based on the optimum results the third least cost option (excluding the cost of ENS) is the expansion of the power generation system using PV systems followed by the combined cycle integrated with a post-combustion CCS system scenario and the CSP technology with a 24/7 operation scenario.

In order to examine the effect of dispatchability of each candidate technology, the cost of ENS was also calculated as part of the optimization procedure.

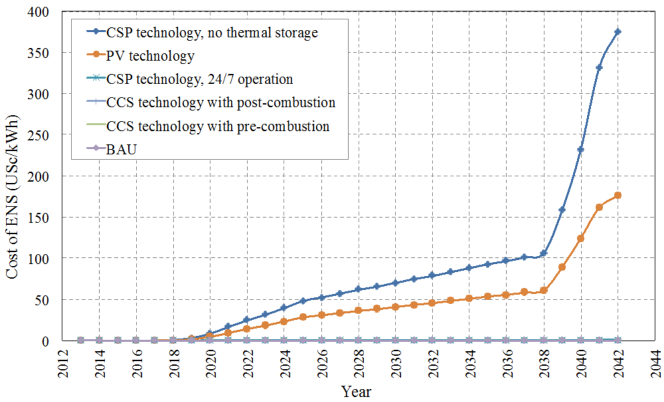

Figure 5: Cost of ENS in real prices (base case scenario, natural gas price 4US$/MMBtu)

This is illustrated in Figure 5 in the case of a natural gas price of 4 US$/MMBtu. However, the results are similar in the case of other variations of natural gas price, since the cost of ENS is technology type dependent.

We observe that where the candidate technologies for the expansion of the power system are (i) a CSP system with no thermal energy storage or (ii) a PV system, the cost of ENS increases considerably on a yearly basis as new capacity additions from those technologies are integrated within the power generation system.

Finally, a comparison of the overall results concerning the optimum total electricity unit cost (generation system electricity unit cost and cost of ENS) calculated for each scenario is presented in Table 3, in ranking order for all natural gas price variations investigated.

We observe that, taking into account the cost impact of ENS on the total electricity unit cost of each configuration, the ranking order is the same for all natural gas price variations.

The most promising sustainable candidate technologies, or combination of these technologies, are in order of rank: (i) combined cycle integrated with a post-combustion CCS system, (ii) combined cycle integrated with a pre-combustion CCS system, and (iii) parabolic trough CSP technology with 24/7 operation. The other candidate sustainable technologies have a considerable adverse impact on system reliability since their dispatchability is marginal, leading to power interruptions and thus high ENS cost.

5. Conclusions

In this work, estimations are made of the ENS in a power capacity expansion problem in the case of integration of intermittent sustainable technologies. For this purpose part of the power generation system of the UAE was examined. Five capacity expansion scenarios using sustainable power generation technologies were investigated, including the integration of CCS technologies and solar-based RES-E systems (intermittent systems as well as dispatchable systems using thermal storage), and compared with the business as usual (BAU) scenario for various natural gas prices.

Based on the input data and assumptions made and taking into account the cost of ENS, the results indicated that the BAU scenario is the least cost option. However, if the UAE move towards the use of sustainable power generation technologies in order to reduce carbon dioxide emissions, the most suitable alternative technologies are: (i) natural gas combined cycle technology integrated with CCS systems, and (ii) concentrated solar power systems with 24/7 operation. The other candidate sustainable technologies have a considerable adverse impact on system reliability since their dispatchability is marginal, leading to power interruptions and thus high ENS cost.

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Table 3: Optimization results in real prices

Option no.	Candidate technology	Generation system electricity unit cost, US$/kWh	Cost of ENS, US$/kWh	Total electricity unit cost, US$/kWh
Natural gas price 4 US J/MMBtu				
a	BAU	2.3546	0.0001	2.3547
c	Combined cycle with a post-combustion CCS	2.7360	0.0004	2.7364
b	Combined cycle with a pre-combustion CCS	3.8257	0.0001	3.8258
f	Parabolic trough CSP with 24/7 operation	3.5329	0.3554	4.2883
d	PV park	3.3753	41.4492	44.8245
e	Parabolic trough CSP with no thermal storage	6.0276	76.4829	82.5106
Natural gas price 6 US$/MMBtu				
a	BAU	2.5196	0.0001	2.5797
c	Combined cycle with a post-combustion CCS	3.0646	0.0003	3.0649
b	Combined cycle with a pre-combustion CCS	4.1622	0.0004	4.1626
f	Parabolic trough CSP with 24/7 operation	6.1244	0.3960	6.5204
d	PV park	3.5314	41.4492	44.9806
e	Parabolic trough CSP with no thermal storage	8.3696	76.4829	84.8525
Natural gas price 8 US$/MMBtu				
a	BAU	2.8047	0.0001	2.8048
c	Combined cycle with a post-combustion CCS	3.3932	0.0003	3.3935
b	Combined cycle with a pre-combustion CCS	4.4988	0.0004	4.4992
f	Parabolic trough CSP with 24/7 operation	6.2048	0.3960	6.6008
d	PV park	3.6874	41.4492	45.1366
e	Parabolic trough CSP with no thermal storage	8.5590	76.4829	85.0420
Natural gas price 10 USJ/MMBtu				
a	BAU	3.0294	0.0001	3.0295
c	Combined cycle with a post-combustion CCS	3.7214	0.0003	3.7217
b	Combined cycle with a pre-combustion CCS	4.8349	0.0004	4.8353
f	Parabolic trough CSP with 24/7 operation	6.2851	0.3960	6.6811
d	PV park	3.8433	41.4492	45.2925
e	Parabolic trough CSP with no thermal storage	8.7482	76.4829	85.2311

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