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Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems

Method comments to a NEA report

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1. Introduction

OECD Nuclear Energy Agency (NEA) released a new report on 29 November 2012. The study recommends that decision-makers should take full electricity system costs into account in energy choices and that such costs should be internalised according to a "generator pays" principle.

The study, entitled *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems*, addresses the increasingly important interactions of variable renewables and dispatchable energy technologies, such as nuclear power, in terms of their effects on electricity systems.

System effects refer to the costs above plant-level costs to supply electricity at a given load and level of security of supply. The NEA report focuses on "grid-level system costs", the subset of system costs mediated by the electricity grid, which include a) the costs of extending and reinforcing transport and distribution grids as well as connecting new capacity, and b) the costs of increased short-term balancing and maintaining the long-term adequacy of electricity supply. More information is available from http://www.oecd-nea.org/press/2012/2012-08.html

In this document we will describe in more details the NEA report concerning System Effects in Low-carbon Electricity Systems. The main sources are (OECD-NEA, 2012) and (Cometto-Keppler, 2012). We will also comment on the results.

2. Summary

The NEA report has several interesting chapters including the ones describing the nuclear technology and details concerning how to make nuclear power more flexible and possibility to interact with SmartGrids. The parts where they compare system costs of the generators is what we are commenting. The general findings concerning quantitative results they state on grid costs are The general findings concerning the here performed analysis concerning quantitative results are

1) The NEA report sometimes uses a "green field study", i.e. the question is the consequences concerning system design if a system is constructed from the beginning with, e.g., wind power in comparison with, e.g., nuclear power. Sometimes they instead use marginal impact, i.e., consequences concerning change or todays power systems. It is not easily found in the report whether they use one or the other method and it is not clear if they recommend one or the other.
2) It is important that system issues are recognized. However, a general question is when and why one should apply a "generator pays" principle and when to apply "pay generator" principle. The common method in most markets is that producers are paid for what they deliver, i.e. "pay producer" principle, i.e., they do no pay for what they do not deliver. One example is "power system adequacy", i.e., there should be enough capacity to meet the peak load. If, e.g., a power plant (reserve plant or other plant) delivers during peak load and is paid for this, then this issue is already "internalized", since units that do not deliver will not get this payment. At the end it will anyhow be the consumers who pay.

Results concerning "Back-up costs (adequacy)". Detailed analysis found in chapter 4

3) The NEA method calculate this cost [USD/MWh] as the product of {CCO: Capacity COmpensation, [MW]} and {the yearly cost of CPC: Competitors Portfolio Choice [USD/MW]} divided with the yearly production of the source [MWh].
4) The CCO is with the NEA method calculated as the difference between weighted mean capacity and the capacity credit. This is a relevant method to estimate the amount of extra capacity needed in a case with too high risk of capacity deficit.
5) The CPC is with the NEA method calculated with a "green field approach" where a so-called "least cost approach" is used.
6) This method sets the value to zero of energy production higher than the yearly mean.
7) The simulated CPC means that one have to assume a capacity market or other types of compensation to receive this "least cost approach".
8) NEA also proposes an alternative method for estimation of the CPC. However also this method is based on a "green field approach" combined with "least cost approach". In a single numerical example it is shown that the wind power causes a lower cost in the CPC (extra value of wind power = 2,3 USD/MWh). But in order to make the competitors to really select this portfolio, they have to be compensated with, e.g., a capacity market. This means, e.g., an extra subsidy to nuclear power of 12,7 USD/MWh.
9) If one uses OCGT (Open Cycle Gas Turbines) as the backup cost, and one assume that extra capacity is needed, then the cost is in the range of 5 USD/MWh (average 4,3 MUSD/MWh) at 10% energy from wind power or solar power. This corresponds to 2,7% of the cost of wind and solar power using NEA data.
10) Extra capacity is, however, only needed if there is not capacity enough in the system. It can also be noted that SmartGrid solutions including Demand Side Management can provide more cost efficient solutions that OCGT.
11) The conclusion is that "green field study approach" is not relevant since the current discussion is how we change the system from today. If more production is needed then OCGT will be selected since it provides the solution with lowest cost. But if capacity is not needed (in case of already enough capacity) or if DSM can be implemented, then the cost will be lower than 5 USD/MWh.

Results concerning "balancing costs". Detailed analysis found in chapter 5

12) In this part NEA mainly refers to other reports and they have not performed any own calculations concerning variable renewables.

Results concerning "Grid connection". Detailed analysis found in chapter 6

13) There is a cost for grid connection to the closest point that can accept the production from a source. The aim of NEA:s report seems to be to internalize the costs for this connection. This is, however, the most common approach in most systems so this cost is already mainly internalized.
14) If one compare the NEA:s costs for on-shore wind power with the current feed-in tariffs (which is used to finance all the costs for the wind power owner) for Finland and Germany it is clear that NEA:s costs also include the cost for grid connection.

Results concerning "Grid reinforcement and extension". Detailed analysis found in chapter 7

15) In the NEA model, the costs for "Grid reinforcement and extension" are taken from references concerning wind power and solar power. However for other sources, such as nuclear power, coal and gas it is stated that "In the NEA model, no reinforcement costs are attributed to dispatchable

technologies owing to the consideration that those power plants can be located in proximity the load centres".

16) The NEA statement though means that no transmission grid is needed in systems where there is no wind or solar power. If one make calculations for the 400 kV transmission grid in France and Sweden, then the costs for these are 1,56 USD/MWh (France, nuclear power), and 3,75 USD/MWh (Sweden, mainly nuclear power but also hydro).
17) However, the general question is how and why this type of costs should be internalized to the producers. Transmission lines are often used by several actors, including trading through a country. There is a benefit, both for the consumers and for the producers, to have a strong transmission system. So there is a question why this cost should be only internalized to different producers.

Final comments.

18) If one has a power system with market pricing, then there will be high prices in peak load situations. If one in this system has a power plant that produces a lot, then the income is high while it will be low if the production is low. This means that the cost of "peak load availability" is internalized in these systems. I.e. application of the "pay generator" principle.
19) The "balancing costs" have the same structure: If a power plant can, e.g., up-regulate and provide power to the regulating market, then this power is normally better paid than other power, which means that flexibility is incentivized. If a power producer, on the other hand, cannot supply a perfect forecast, there may be penalizing models in the im-balance treatments which means that the benefits are lower. This means that the "balancing costs" are internalized in these systems. I.e. application of the "pay generator" principle.
20) With larger amounts of wind and solar power, there will be a (from these plants point of view) negative correlation between the price and the production since high production in plants with low marginal costs (wind and solar) will reduce the need for other power plants which will reduce the power price on the market. This means that the more wind- and solar power, the stronger this relation. This means that this "balancing cost" is internalized in these systems. I.e. application of the "pay generator" principle.
21) The general result is that the "system costs" are either comparatively small (in Finland case, with 10% wind power, up to 3,4% of total cost) or already included in the market.

The final conclusion is that there are several question marks concerning the calculation methods used to calculate the "grid-level systems costs" in the (OECD-NEA, 2012) report.

3. The NEA report, quantitative results

In (OECD-NEA, 2012), page 17-18, the following tables are presented concerning grid-level system costs.

Table ES.2: **Grid-level system costs in selected OECD countries** (USD/MWh)

Finland												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.06	0.06	0.00	0.00	8.05	9.70	9.68	10.67	21.40	22.04
Balancing costs	0.47	0.30	0.00	0.00	0.00	0.00	2.70	5.30	2.70	5.30	2.70	5.30
Grid connection	1.90	1.90	1.04	1.04	0.56	0.56	6.84	6.84	18.86	18.86	22.02	22.02
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	0.20	1.72	0.12	1.04	0.56	4.87
Total grid-level system costs	**2.37**	**2.20**	**1.10**	**1.10**	**0.56**	**0.56**	**17.79**	**23.56**	**31.36**	**35.87**	**46.67**	**54.22**

France												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.08	0.08	0.00	0.00	8.14	8.67	8.14	8.67	19.40	19.81
Balancing costs	0.28	0.27	0.00	0.00	0.00	0.00	1.90	5.01	1.90	5.01	1.90	5.01
Grid connection	1.78	1.78	0.93	0.93	0.54	0.54	6.93	6.93	18.64	18.64	15.97	15.97
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	3.50	3.50	2.15	2.15	5.77	5.77
Total grid-level system costs	**2.07**	**2.05**	**1.01**	**1.01**	**0.54**	**0.54**	**20.47**	**24.10**	**30.83**	**34.47**	**43.03**	**46.55**

Germany												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.04	0.04	0.00	0.00	7.96	8.84	7.96	8.84	19.22	19.71
Balancing costs	0.52	0.35	0.00	0.00	0.00	0.00	3.30	6.41	3.30	6.41	3.30	6.41
Grid connection	1.90	1.90	0.93	0.93	0.54	0.54	6.37	6.37	15.71	15.71	9.44	9.44
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	1.73	22.23	0.92	11.89	3.69	47.40
Total grid-level system costs	**2.42**	**2.25**	**0.97**	**0.97**	**0.54**	**0.54**	**19.36**	**43.85**	**27.90**	**42.85**	**35.64**	**82.95**

Republic of Korea												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.03	0.03	0.00	0.00	2.36	4.04	2.36	4.04	9.21	9.40
Balancing costs	0.88	0.53	0.00	0.00	0.00	0.00	7.63	14.15	7.63	14.15	7.63	14.15
Grid connection	0.87	0.87	0.44	0.44	0.34	0.34	6.84	6.84	23.85	23.85	9.24	9.24
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	2.81	2.81	2.15	2.15	5.33	5.33
Total grid-level system costs	**1.74**	**1.40**	**0.46**	**0.46**	**0.34**	**0.34**	**19.64**	**27.84**	**35.99**	**44.19**	**31.42**	**38.12**

United Kingdom												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.06	0.06	0.00	0.00	4.05	6.92	4.05	6.92	26.08	26.82
Balancing costs	0.88	0.53	0.00	0.00	0.00	0.00	7.63	14.15	7.63	14.15	7.63	14.15
Grid connection	2.23	2.23	1.27	1.27	0.56	0.56	3.96	3.96	19.81	19.81	15.55	15.55
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	2.95	5.20	2.57	4.52	8.62	15.18
Total grid-level system costs	**3.10**	**2.76**	**1.34**	**1.34**	**0.56**	**0.56**	**18.60**	**30.23**	**34.05**	**45.39**	**57.89**	**71.71**

United States												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.04	0.04	0.00	0.00	5.61	6.14	2.10	6.85	0.00	10.45
Balancing costs	0.16	0.10	0.00	0.00	0.00	0.00	2.00	5.00	2.00	5.00	2.00	5.00
Grid connection	1.56	1.56	1.03	1.03	0.51	0.51	6.50	6.50	15.24	15.24	10.05	10.05
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	2.20	2.20	1.18	1.18	2.77	2.77
Total grid-level system costs	**1.72**	**1.67**	**1.07**	**1.07**	**0.51**	**0.51**	**16.30**	**19.84**	**20.51**	**28.26**	**14.82**	**28.27**

Table 1 System costs from (OECD-NEA, 2012) page 17-18.

Below we will try to explain how these results were calculated. The calculated results depend on the applied methods as well as the used data in the methods.

4. Back-up costs (adequacy)

The background for these costs is stated on (OECD-NEA, 2012), page 125: ”The NEA model computes the investment costs of new back-up capacity as that of the country specific least-cost generating mix of dispatchable technologies, or as that of the cheapest technology available (either gas turbine or storage).”

In (OECD-NEA, 2012), page 148 it is then stated: “The calculation of adequacy costs is more complex, and has been performed in the following steps. For a given country, a given technology and a given penetration level, the firm capacity guaranteed by that technology and the one guaranteed by the existing mix of dispatchable technologies that would provide the same electrical energy output were calculated. The difference between those values gives the amount of additional capacity that must be built in order to achieve the same adequacy level (in addition to the same electricity output) in the two systems. Once the additional generation capacity to be built is known, the investment costs for building this capacity are determined. The NEA model calculates the least-cost capacity mix that can compensate the intermittency of wind and solar power depending on their annual production profile. Given the lack of country-by-country data on wind and solar production, the French values were taken as a common reference for the least-cost shares. While this may seem a rather strong assumption, the general result of a mix of peak- and mid-load technologies is consistent with intuition. Nevertheless, further research would, of course, be needed once country-by-country production profiles for wind and solar power become available.”

The structure of this chapter is to first describe the way NEA has calculated the costs named “back-up costs (adequacy)”, then also apply a version of the method described in (OECD-NEA, 2012), Appendix 4.D. This is followed by commenting on the NEA:s selection of Competitors Portfolio Choice, calculation of adequacy costs using OCGT and finally conclusions on the “back-up (adequacy)” area.

2.1. NEAs method to calculate additional generation capacity

It is stated on (OECD-NEA, 2012), page 148 that: “For a given country, a given technology and a given penetration level, the firm capacity guaranteed by that technology and the one guaranteed by the existing mix of dispatchable technologies that would provide the same electrical energy output were calculated. The difference between those values gives the amount of additional capacity that must be built in order to achieve the same adequacy level (in addition to the same electricity output) in the two systems.”. Further details for this method are obtained from (Cometto-Keppler, 2012): The method will below be illustrated using data for Finland concerning 10% of yearly energy consumption from wind power. The numerical example uses an installed wind power capacity of X=10 MW for illustrative purposes:

a. Estimate the ***capacity credit*** for the source (= Y MW of capacity credit for an installation of X MW means that the load in the system can increase with Y MW with remained power reliability in the system = same Loss of Load Probability in the system, LOLP). The capacity credit is provided in percent: CC=Y/X). In this numerical example CC=0,10=10% (page 146)
b. Estimate the ***capacity factor*** for the source (= X MW of capacity will result in a yearly mean capacity of Z MW, i.e., a mean yearly energy production of Z*8760h. The Capacity Factor is provided in percent, i.e. CF=Z/X). In this numerical example CF= 0,26=26% (page 144)
c. The ***dispatchable capacity***, DC, is then calculated as the amount of conventional capacity (assumed capacity factor of 85%=0,85) that is needed to get the same yearly average power, i.e. Z MW. This means DC=Z/0,85=CF*X/0,85. In this numerical example DC=0,26*10/0,85=3,06 MW.
d. The ***net equivalent capacity***, NEC, is then calculated as the capacity credit of a conventional power mix (assumed capacity credit of 96,7%) with this dispatchable capacity, i.e. NEC=0,967*DC. In this numerical example NEC=0,967*3,06=2,96 MW.
e. The capacity compensation, CCO, is then calculated as the extra capacity that is needed for the X MW to get the same CC as the NEC, i.e. CCO=NEC-CC*X. In this numerical example CCO=2,96-CC*X=2,96-0,10*10=1,96 MW.
f. The cost for the capacity compensation (i.e. the extra cost to get the same CC for the X MW as for a conventional unit), = the ***adequacy cost***, AC, (in USD/MWh) is then calculated. It is then assume that this cost is applied to each MWh of production caused by the CCO in the previous step. See section 2.2.

2.2.NEAs method to calculate the adequacy cost

In (OECD-NEA, 2012), page 148 it is stated: "Once the additional generation capacity to be built is known, the investment costs for building this capacity are determined. The NEA model calculates the least-cost capacity mix that can compensate the intermittency of wind and solar power depending on their annual production profile." Further details for this method are obtained from (Cometto-Keppler, 2012): The method will below be illustrated using data for Finland concerning 10% of yearly energy consumption from wind power (illustrated with an installed wind power capacity of X=10 MW), and also with some more data for Sweden.

The adequacy cost, AC, is calculated as a weighted mean value of the investment costs in a power system with a constant demand of X*CF MW where other capacities are compensating the energy that is not produced by the X MW.

A. Assume a flat block of energy production for a whole year with the capacity X*CF MW.
B. Calculate the duration curve of the X MW production.
C. Calculate how to cover up the production that is not covered by the duration curve. The compensating power is assumed to be covered with different kinds of power plants. The ***resulting mix cost***, RMC, is then used as the cost per MW to compensate for the possible lack of capacity credit (CCO) of the X MW. RMC is in reality an estimation of how the competitors to the X MW will invest, i.e., the Competitors Portfolio Choice, CPC. The RMC (= the cost for CPC) is calculated as the least cost combination of conventional power plants to cover the not produced

power up to the mean production, CF*X, level of the source. For the Finnish case CPC=1128,5 USD/kW which is a mix of 18% coal capital costs + 46% CCGT capital costs + 36% OCGT capital cost. The percentual values are obtained from (Cometto-Keppler, 2012), capital costs of coal and CCGT are from (OECD-NEA, 2012), page 144, while OCGT capital cost used by NEA is 702 USD/kW (Cometto-Keppler, 2012).

D. It can be noted that with this method, the power production which is higher than the yearly mean will not be considered in the calculation. In reality this power will decrease the operation cost in other power plants.

Figure 1 illustrates the method where wind power is taken from Sweden and cost data are taken from Finland. The example consists of a duration curve for 10 TWh of wind power in Sweden, corresponding to 4000 MW. Wind power data corresponds to a wind speeds from 1992 (Magnusson, 2004). The mean value = 10 TWh/8760 h = 1156,7 MW. The CPC is then, according to (Cometto-Keppler, 2012), calculated in the following way: Coal power is assumed to be the most economical solution for utilizations time above 4380h but lower than 7000h, c.f. (OECD-NEA, 2012), page 133. For this case this means 23,9% of the needed capacity. At lower utilization times, but higher than 1410 h, CCGT is assumed to provide the lowest cost. In this case this is for 51,7% of the capacity. For lower utilization times than 1410 hours, the cheapest solution is OCGT. To calculate RMC the investment costs for Finland (CCGT and coal) are from (OECD-NEA, 2012), page 144, while the OCGT cost is 702 USD/kW (Cometto-Keppler, 2012). Using these costs the result becomes RMC=0,239*2133,5+0,517*1069+0,244*702=1233,9 USD/kW.

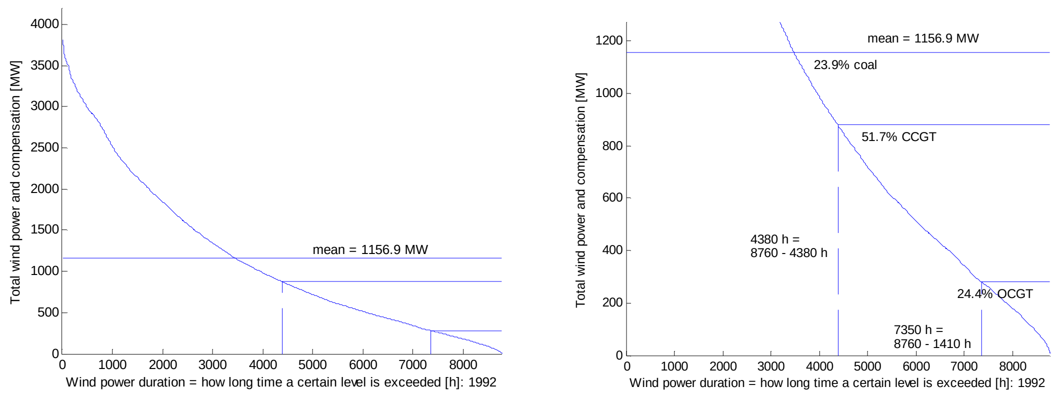

Figure 1: Illustration of Competitors Portfolio Choice and Resulting Mix Cost calculation. Wind power duration curve for 4000 MW wind power and compensation cost for Sweden. Method according to (Cometto-Keppler, 2012). Right hand curve is the left hand curve zoomed.

The next step is then to calculate the adequacy cost for the X MW. This is done in the following way:

i. Calculate the ***needed investment cost***, NIC, for the CCO MW, NIC=CCO*RM. In the numerical example concerning 10 MW of wind power in Finland this is NIC = 1,96*1128,5*1000=2,21 MUSD. (1128,5 used data for Finland but close to the derivation above based on Swedish data: 1233,9).

ii. This cost should then be divided on the ***discounted energy production***, DEP, caused by the X MW. It is then assumed that the life length of the X MW is 25 years and with an assumed discount rate of 7%, (OECD-NEA, 2012), page 148. NEA assumes that investments are performed in the middle of the year, i.e., the present value of future production is (1/1.07)^0.5,……, (1/1.07)^24.5 = 12,054355 (Cometto-Keppler, 2012). This means that the NIC should be spread out on DEP=X*CF*8760*12,054355. In this numerical example DEP=10*0,26*8760*12,054355 =274550 MWh.

iii. The ***adequacy cost***, AC, is then calculated as AC=NIC/DEP=8,05 USD/MWh.

The input data here, capacity credit=CC, capacity factor=CF while resulting mix=RM is a result of an internal NEA calculation, with the method described above and illustrated in Figure 1. From these data it is possible to calculate the AC as

$$AC=RM*(0,967*CF/0,85-CC)/(CF*8760*12.054355) \quad (1)$$

In the report, AC, CC and CF are provided for all examples while RM is not. The resulting mix = RM can therefore be calculated as

$$RM=AC*(CF*8760*12.054355)/ (0,967*CF/0,85-CC) \quad (2)$$

In Table 2 the RM costs are calculated for all cases with wind power and solar power. The calculations are performed using equation 2 where the details are from (Cometto-Keppler, 2012).

Country	Source, 10 MW, 10%	capacity credit in percent, p 146	capacity factor, p 144	Yearly energy production, MWh	Needed compen-sation, CCO MW	AC cost, page 17-18, USD/MWh	NEA RM cost USD/kW, ekv 2
Finland	Onshore wind	10,0%	26,0%	22776	1,96	8,05	1128,8
	off shore wind	10,0%	43,0%	37668	3,89	9,68	1129,4
	solar PV	0,4%	9,0%	7884	0,98	21,4	2067,1
France	Onshore wind	7,0%	21,0%	18396	1,69	8,14	1068,7
	off shore wind	11,4%	34,0%	29784	2,73	8,14	1071,3
	solar PV	0,4%	13,0%	11388	1,44	19,4	1850,8
Germany	Onshore wind	8,0%	23,0%	20148	1,82	7,96	1064,2
	off shore wind	15,0%	43,0%	37668	3,39	7,96	1065,6
	solar PV	0,4%	11,0%	9636	1,21	19,22	1842,9
Korea	Onshore wind	20,4%	26,0%	22776	0,92	2,36	705,9
	off shore wind	26,7%	34,0%	29784	1,20	2,36	707,3
	solar PV	0,4%	14,0%	12264	1,55	9,21	876,9
United Kingdom	Onshore wind	22,0%	28,0%	24528	0,99	4,05	1215,2
	off shore wind	29,9%	38,0%	33288	1,33	4,05	1219,1
	solar PV	0,4%	10,0%	8760	1,10	26,08	2509,0
United States	Onshore wind	13,5%	23,0%	20148	1,27	5,62	1077,6
	off shore wind	40,0%	43,0%	37668	0,89	2,1	1069,1
	solar PV	27,3%	18,0%	15768	-0,68	0	0,0

Table 2 Calculation of the regulating mix cost for the different cases with 10% of the energy from wind or solar power.

The costs in the right column are then the weighted costs with the method described above and illustrated in Figure 1. In order to get an understanding, one can then compare these costs with the costs presented in (OECD-NEA, 2012), page 144. It is then shown that for wind power the costs are not OCGT but more CCGT while for solar power the cost levels are around costs for coal power.

2.3.NEAs proposed, but not used, method to calculate the adequacy cost

This method is close to the one presented in (OECD-NEA, 2012), appendix 4.D. If we start with the method: Below a basic study of this has been performed for Sweden, studying a load of 139 TWh which is real load from 2011, (Svenska Kraftnät, 2001-2011). This load which is then either supplied partly with 15,2 TWh of wind power (15,2 TWh/139 TWh=10,9%) or alternatively 15,2 TWh as a constant production (15,2 TWh/8760h = 1735.4 MW) over the year. The data is the load from 2011 and wind power production synthetically produced from real wind measurements from 1992 all over Sweden (Magnusson, 2004). Both data series are hourly data. The net load duration curve in case of wind is calculated from taking the difference hour by hour between load and wind. The remaining load (139 – 15,2=123,8 TWh), the CPC, is assumed to be supplied in the same way as in the NEA method in section 2.2, i.e, (net load for either wind or constant level) it is covered in a cost minimizing level, i.e., nuclear power when utilization time > 7000h, coal when between 4380 h and 7000 h, OCGT when between 1410 h and 4380 h and OCGT when lower than 1410 h. The result is shown for the two cases in Figure 2.

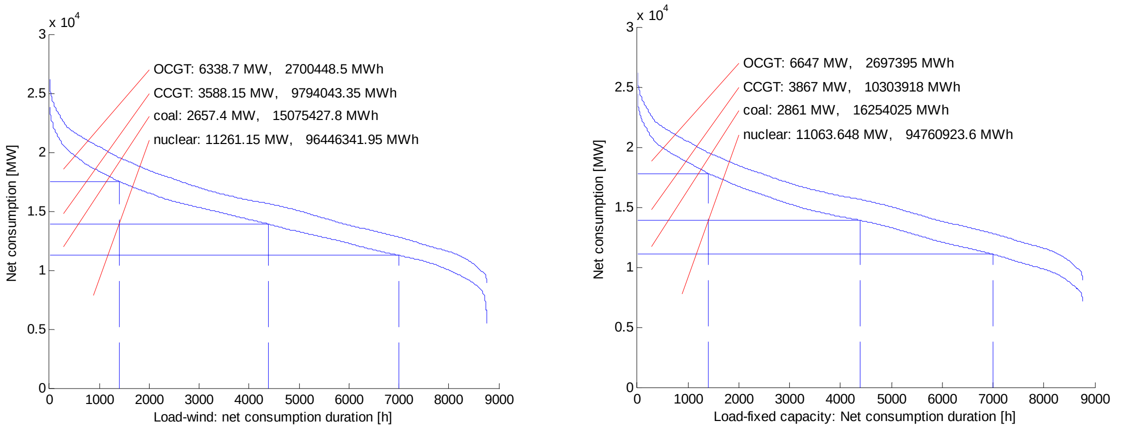

Figure 2 Competitors Portfolio Choice assumed to be set as least cost supply. CPC covers the net load duration curves for the case with 15 TWh wind (left) and constant power =1735.4 MW (right).

If one then compares the result in Figure 2, one gets the results as shown in Table 3.

source	investm. USD/kW	cost/year USD/kW	energy USD/MWh	wind-MW	wind-MWh	wind-MW cost MUSD	wind MWh cost MUSD	fixed-MW	fixed-MWh	fixed MW cost MUSD	fixed MWh cost MUSD
ocgt	702	58,23522	100	6338	2700448	369,0948	270,0448	6647	2697395	388,7783	269,7395
ccgt	1069	88,68013	65,7	3588	9794043	318,1843	643,468625	3867	10303918	342,9261	676,967413
coal	2133	176,9455	24,2	2657	15075428	470,1442	364,825358	2861	16254025	506,241	393,347405
nuclear	4101	340,2032	24	11261	96446342	3831,028	2314,71221	11064	94760924	3764,008	2274,26218
			total	23844	124016261	4988,452	3593,05099	24439	124016262	5001,954	3614,31649

Table 3 Comparison of data from Figure 2, cost data from (OECD-NEA, 2012), page 144 concerning Finland, OCGT costs from (Cometto-Keppler, 2012) and Energy costs for OCGT assumed to be 100 USD/MWh .

From Table 3 it is then possible to make the comparison between the case with wind power and the alternative with constant production. The result is shown in

Table 4.

Data type	Net-load with wind MUSD	Net-load with constant production MUSD	Wind minus constant MUSD	Wind minus constant USD/MWh
MW costs	4988	5002	-13,5	-0,9

MWh costs	3593	3614	-21,3	-1,42
total	8582	8616	-34,7	-2,32

Table 4 Calculation of difference between costs in Competitors Portfolio Choice between wind and fixed power alternatives.

The result in this case is then that investment and operational cost of the Competitors Portfolio Choice has a lower value in the case of wind power. The explanation to this is that wind power has a seasonal correlation with the load so wind power produces more in the winter than in the summer. This means that wind power has a slightly higher value than the fixed source, since it produces more when needed. The difference is around 2,3 USD/MWh.

2.4.Comments to NEAs selection of Competitors Portfolio Choice

It is important to note that the applied Competitors Portfolio Choice in sections 2.2 and 2.3 are based on "total cost minimization". The question is if this is what the competitors will do. One important issue is the function of the market. In a so called "perfect market" or a market with "perfect competition", then the price will be set by marginal cost, i.e., the cost of the current power plant with the highest operating cost. If we study both figures in Figure 2, then it is clear that for the 1410 hours with highest net load the Marginal Cost, MC, is the operating cost of OCGT, here assumed to be MC =100 USD/MWh. In the interval 1410-4380 h it is CCGT (MC=65,7 USD/MWh), 4380-7000 h coal (MC=24,2 USD/MWh) and 7000-8760 h nuclear (MC=24 USD/MWh). The income for each power source can then be calculated as the sum of the energy production in each interval times the MC in each interval. The costs for each power source are already estimated in Table 3, and in Table 5 the costs are shown together with the income from selling at marginal cost.

source	investm. USD/kW	cost/year USD/kW	energy USD/MWh	total cost MUSD/year	total cost USD/MWh	total income MUSD/year	total income USD/MWh	income USD/MWh
OCGT	702	58,23522302	100	639,139643	**236,67912**	270,04	**100,0000185**	-136,6791
CCGT	1069	88,68013305	65,7	961,652942	**98,187535**	817,00	**83,41829279**	-14,769242
coal	2133	176,9454853	24,2	834,969512	**55,386123**	976,38	**64,7663726**	9,38024943
nuclear	4101	340,2032045	24	6145,74049	**63,721862**	4922,04	**51,03397338**	-12,687889
wind						802,5099533	**52,78976144**	

Table 5 Cost and income for the left case in Figure 2, i.e. wind power and the Competitors Portfolio Choice modeled as the combination with lowest cost.

There are then some issues concerning this method, i.e. to use the assumption that Competitors Portfolio Choice will be based on the least cost portfolio:

- Table 5 shows that if the lowest cost method is applied then OCGT, CCGT and nuclear power will make a loss. Only coal power makes a positive result. For wind power only the income can be calculated since the cost is not defined. This means that in a deregulated market these investments will not be performed since the investors make a loss. This type of question is a general challenge in power system investment analysis. One issue is, e.g., to have capacity markets which is a way to pay units to stay on the market. If this is the case here then, e.g., nuclear power has to be compensated with 12,69 USD/MWh, otherwise these units will not be built. This means that one cannot, without a lot of important assumptions e.g. capacity markets, just assume that the competitors will make a "least cost investment".

- Another issue is that as shown in Figure 2 nuclear power is the only source during 8760-7000=1760 hours/year corresponding to more than 2 months. As shown in (OECD-NEA, 2012) there are possibilities to perform control in nuclear power system, but to rely on 100% on only nuclear power, which e.g. means that if there is an outage then the immediate backup should still come from nuclear, is not stable. In reality there must be other power plants to meet load variations. Nuclear power can *contribute*, but not make the whole balancing.
- The method illustrated in Figure 2 is based on the assumption of the optimal utilization times of 1410, 4380 and 7000 hours respectively, (OECD-NEA, 2012), page 133. But it must be noted that the costs applied from the table in (OECD-NEA, 2012), page 144 and used in Table 4, will not result in, e.g., 7000 hours. It is important to note that this use of different numbers reflects the uncertainty of how investments are performed in reality. Nu investor can be totally sure about the future and based on this make a "perfect" investment.
- The whole set-up of both NEA:s methods in sections 2.2 and 2.3 are based on so-called "green-field studies", i.e. one start from no power system at all and then one know exactly all prices, demands etc. And from these assumptions one estimate some costs. This is then not relevant when one have a certain system where one will make changes.

The general conclusion is that if one wants competitors to a new source to select a portfolio based on "lowest cost mix" then one have to have other compensating mechanisms for the conventional power sources and in the studied example these compensation will be much higher than the size of the cost (negative) for wind power concerning changed least cost Competitors Portfolio Choice.

2.5. Adequacy cost calculations using OCGT as Competitors Portfolio Choice

The NEA method in section 2.2 combines the issue of capacity credit (NEC calculation) with a cost calculation which is not related to the cheapest way to cover this extra needed capacity. The extra capacity needed to cover the peak will not have a utilization time longer than 1410 hours, which means that OCGT (with a NEA cost of 702 USD/kW). The reason why NEA gets a higher cost is mainly the method, but also to a certain extent the data.

The production unit with the lowest investment cost is OCGT. This means that if extra capacity is needed then this technology will be chosen as long as the utilization time is lower than 1410 hours. It must, however, also be noted that Smart-Grid-applications such as Demand Side Management, can often be an even cheaper solution. Below, three cases of capacity credit calculation will be shown. They are the NEA cases but with OCGT costs, a Swedish case and finally a European case.

2.5.1. Adequacy cost calculations using OCGT as Competitors Portfolio Choice for NEA data

Concerning data the following first has to be noted: The capacity credit data for on-shore and off-shore wind for, e.g., Finland are both 10% (OECD-NEA, 2012), page 146, while the capacity factors are 26% and 43% respectively (OECD-NEA, 2012), page 144. Assume, e.g., 10 TWh of wind power. This then means that the needed capacities will be [10 TWh/8760h/0,26=] 4390 MW (offshore) and [10 TWh/8760h/0,43=] 2655 MW. The mean capacity in both cases are [10 TWh/8760h=] 1142 MW. With the assumption of 10% capacity credit, this means that it is [0,10*4390=] 439 MW (onshore) and [0,10*2655] = 265,5 MW (offshore). It is not, without any further explanation, realistic to assume that a certain amount of offshore wind power should produce less that than onshore wind power in high load situations. One should then consider the same relation between capacity credit and capacity factor, CC/CF, if all data is not available. In Table 6 this method is applied for Off shore wind power in Finland.

With the assumed change of data it is now possible to calculate the “maximum extra cost” per MWh if extra capacity is needed. This is done using eq. 1. The result is shown in Table 6

Country	Source, 10 MW, 10%	capacity credit in percent, p 146	capacity factor, p 144	Needed compen-sation, CCO MW	AC cost, OCGT, eq.1, USD/MWh	Investm. Cost USD/kW, p 144	Variable cost USD/MWh , p 144	Investm. + variable USD/MWh	extra cost in percent for CC
Finland	Onshore wind	10,0%	26,0%	1,96	5,01	2348,6	21,9	107,44	4,66%
	off shore wind	16,5%	43,0%	3,24	5,01	4893,0	46,3	154,06	3,25%
	solar PV	0,4%	9,0%	0,98	7,27	4273,5	30,0	479,66	1,52%
France	Onshore wind	7,0%	21,0%	1,69	5,35	1912,0	20,6	106,82	5,01%
	off shore wind	11,4%	34,0%	2,73	5,33	3824,0	32,4	138,91	3,84%
	solar PV	0,4%	13,0%	1,44	7,36	4273,5	81,0	392,30	1,88%
Germany	Onshore wind	8,0%	23,0%	1,82	5,25	1934,0	36,6	116,23	4,52%
	off shore wind	15,0%	43,0%	3,39	5,24	4893,0	46,3	154,06	3,40%
	solar PV	0,4%	11,0%	1,21	7,32	2150,0	52,9	237,99	3,08%
Korea	Onshore wind	20,4%	26,0%	0,92	2,35	2348,6	21,9	107,44	2,18%
	off shore wind	26,7%	34,0%	1,20	2,34	4893,0	32,4	168,68	1,39%
	solar PV	0,4%	14,0%	1,55	7,37	2673,0	30,0	210,81	3,50%
United	Onshore wind	22,0%	28,0%	0,99	2,34	2344,1	30,9	110,18	2,12%
Kingdom	off shore wind	29,9%	38,0%	1,33	2,33	4052,9	32,2	133,20	1,75%
	solar PV	0,4%	10,0%	1,10	7,30	3150,0	39,9	338,20	2,16%
United	Onshore wind	13,5%	23,0%	1,27	3,66	1973,0	8,6	89,84	4,08%
States	off shore wind	40,0%	43,0%	0,89	1,38	3953,0	23,6	110,66	1,25%
	solar PV	27,3%	18,0%	-0,68	-2,52	3877,5	5,7	209,70	-1,20%

Table 6 Adequacy cost using OCGT as Competitors Portfolio Choice.

In Table 6 also the OCGT cost as share to total cost for wind and solar power according to (OECD-NEA, 2012), page 144 are shown. The average value is 2,7% of total cost.

2.5.2. Adequacy cost calculations using OCGT for a Swedish wind power case

The capacity credit of wind power treats the possibility of wind power to increase the reliability of the power system. Figure 3 shows an illustrative example of a weekly load where the available capacity is 3200 MW. This implies that there will be capacity deficit during 40 hours in that week.

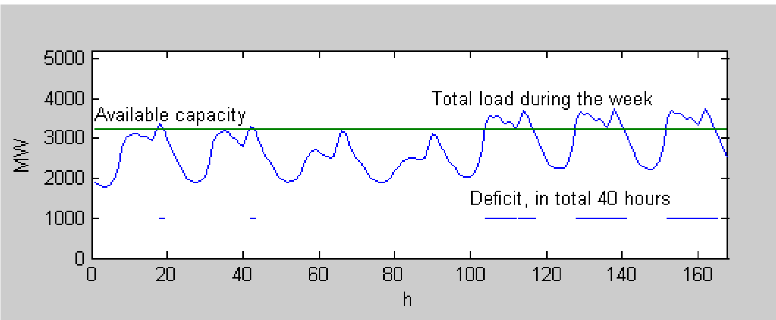

Figure 3 Occasions with capacity deficit without wind power

Wind power is now introduced in this system and that available capacity is increased according to Figure 4. In the figure real wind power has been scaled up to get a significant production level. The consequence of this amount of wind power is that the number of hours with capacity deficit has decreased to 25.

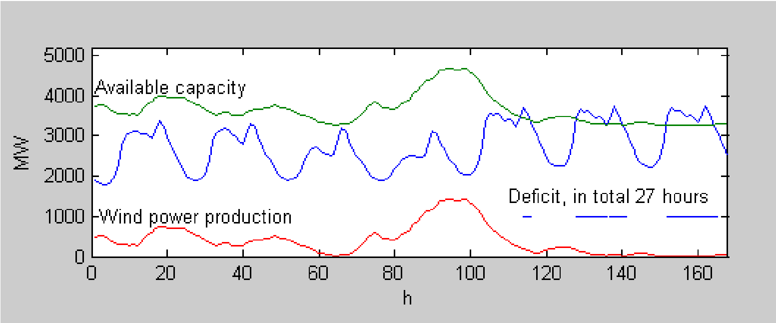

Figure 4 Occasions with capacity deficit with wind power

This means that the reliability of the power system has increased thanks to wind power, i.e. lower LOLP, Loss of Load Probability. Assume that the reliability was acceptable before wind power was installed. This implies that the power system can meet a higher demand with wind power if the same reliability level is accepted.

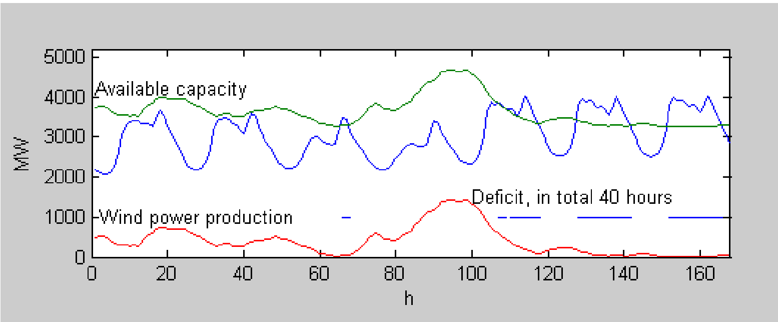

Figure 5 Occasions with capacity deficit with wind power and load +300 MW

In Figure 5 it is shown that if the load increases with 300 MW during each hour, then the number of hours with capacity deficit increases to 40. This implies that the capacity credit of the studied amount of wind power measured as equivalent load carrying capability is 300 MW.

It should be noted that Figure 3 to Figure 5 only gives an illustration of how to estimate the capacity credit. The risk of capacity deficit is normally much lower than the here shown figures, often much lower than 0.1%. It is also important to note that the risk of capacity deficit cannot be zero for this calculation. It should also be noted that it is not only the peak demand that is of interest, but also other situations.

In Sweden peak load situations are not so common. They do not occur every year and then only for some hours. Anyhow it is important that there is also enough capacity during these situations. In the basic ELCC (Equivalent Load Carrying Capability) method, as illustrated above, one should consider many high load situations, trading capabilities with other areas and also outages in units. Below an analysis is presented where the availability of wind and nuclear power during peak load situations is presented. It is important to compare available capacities corresponding to the same amount of yearly energy. The reason is that if one compare two sources that could generate W TWh/year, then it is relevant to compare the capacity credit for these two sources, i.e. the capacity credits for two sources with same yearly energy production. In general more capacity has to be built to produce the same energy with wind compared to coal or nuclear. Yearly mean power is directly related to yearly energy production as

$$\text{Yearly mean power in MW} = [\text{Yearly energy in TWh}]\cdot 10^6/[8760\ \text{h}]$$

Below the availability of wind power and nuclear power during peak load situations are presented. For the calculation of capacity credit one should consider the whole system including load and production in Sweden and neighboring countries as well as transmission capacities and equipment availability. The capacity credit for wind power has internationally been reported to be between 10-40 percent of installed capacity (Final report, Phase one 2006-08, IEA - Wind Task 25), depending on the correlation between load and demand. In Sweden the peak loads are during winter and it is windier during the winter compared to yearly mean.

Wind power in Sweden during peak load

An important issue is the wind availability during peak load. The yearly peak loads (column 3) and when they occurred has been taken from yearly reports from Svensk Energi. In the report "Production variation from wind power, Elforsk report 04:34", a possible installation of 4000 MW of wind power in Sweden has been studied. The report is based on real wind data for the period 1992-2002 and present hourly MW levels for 56 sites and 10 years. In Table 1, column 4, the production during the reported Swedish peak load situations is studied. The data corresponds to in installation of 4000 MW of wind power with a mean production of 10 TWh/year, i.e. a mean production of 1142 MW.

Date	time	Peak load [MW]	Wind power [MW]	Share of installed capacity [percent]	Share of yearly mean [percent]
1992-01-20	08-09	23900	459,9	11,5	40,3
1993-12-14	16-17	24400	468,0	11,7	41,0
1994-02-14	08-09	24400	1134,8	28,4	99,4
1995-12-21	08-09	24400	1312,1	32,8	114,9
1996-02-07	08-09	26300	549,8	13,8	48,2
1997-02-17	08-09	25500	1941,1	48,5	170,0
1998-12-07	16-17	24600	2253,0	56,3	197,4
1999-01-29	08-09	25800	823,7	20,6	72,2
2000-01-24	08-09*	26000	520,5	13,0	45,6
2001-02-05	17-18	26800	1915,8	47,9	167,8

Average value:	1137,9	28,4	99,7

Table 7 Wind Power during peak load (*for year 2000, date is confirmed but not hour)

The conclusion is that the mean production during peak load situations is around the same as yearly mean. This was also the conclusion from an earlier study of wind availability in Sweden during eight load peaks ("Vindkraftens tillgänglighet vid hög last, Söder, KTH, 1987).

Nuclear power in Sweden during peak load

In order to get a comparison with another source, here the Swedish nuclear power production in the 10 today (2012) existing reactors during the last 10 Swedish peak load situations is studied. There have been changes in the installed capacity which is shown in Table 2, right column.

Date	time	Peak load [MW]	Nuclear power [MW]	Share of installed capacity [percent]	Share of yearly mean [percent]	Yearly prod. [TWh]	Yearly mean [MW]	Installed capacity [MW]
2003-01-31	08-09	26400	8840	93,6%	118,2%	65,5	7477,2	9441
2004-01-22	08-09	27300	9432	99,6%	110,2%	75	8561,6	9471
2005-03-03	08-09	25800	8182	91,3%	102,7%	69,8	7968,0	8961
2006-01-19	17-18	26300	8928	99,6%	120,3%	65	7420,1	8961
2007-02-21	18-19	26200	7083	78,1%	96,5%	64,3	7340,2	9074
2008-01-23	17-18	24500	9000	100,7%	128,6%	61,3	6997,7	8938
2009-01-16	08-09	24800	8741	93,6%	153,1%	50	5707,8	9342
2009-12-21	16-17	24800	5330	57,1%	93,4%	50	5707,8	9342
2010-12-22	17-18	26700	8691	95,0%	136,9%	55,6	6347,0	9151
2011-02-23	08-09	26000	7931	84,7%	119,8%	58	6621,0	9363
Average value			**8215,8**	**89,3%**	**118,0%**	**61,5**	**7014,8**	

Table 8: Nuclear Power in Sweden during ten peak load situations.

Table 8 shows the production in column 4 during the last ten load peaks (column 3) in Sweden. Since the installed capacity has changed over this period, the share of installed capacity has to be first calculated per year. The average value was 89,3 percent. For a comparison with wind power one should compare with the yearly mean production, see columns 6-8. The result is then an average contribution during peak of 118,0 percent of yearly mean.

Comparison of peak load contribution

When different alternatives in power system are to be evaluated and compared, the unit costs as well as the system impact have to be considered. Every investment (a new line, a new source of any kind, a new load) has a system impact since it will change the operation of the system. Without any change of system operation there is no need of the new equipment! System impact include, e.g., changed losses, changed use of reserve power, changed use of lines, changed economic result of competitors, changes system reliability, changed interest for competitors to keep their units, changed need of other investments etc.

Capacity credit is only one of these system impacts. It must, however, first be stated that the value of the capacity credit of a certain new power plant is zero if the risk of capacity credit is zero since the basic definition of capacity credit is how the new plant can contribute to lower the risk of capacity credit.

Here a simplified calculation is performed. The method is basically to compare the peak load contribution where the alternative is to meet the peak load with gas turbines, OCGT. The method will first be shown and then commented.

The cost of OCGT is 58235 USD/MW,year (702 USD/kW, 7% interest rate) and has an assumed availability of 95 percent. In addition to this there is a fuel cost of around 100 USD/MWh. With an assumed production during 10 hours per year the yearly operating cost becomes 10*100= 1000 USD.

Example: The question is to compare peak load contribution of 10 TWh wind power (data from Table 7) with 10 TWh nuclear power with historic performance, see Table 8. 10 TWh (4000 MW) of wind power has the peak contribution of 1137,9 MW. 10 TWh nuclear power provides a peak contribution of provides a peak contribution of 10/61,5*7014,8*1,091=1345,9 MW. The calculation is based on Table 8 data shows that 61,5 TWh/year corresponds to 7014,8 MW mean power which means a peak contribution of 118,0 percent of mean.

If the same average peak contribution is expected then one in the wind case has to add 1345,9-1137,9=208,0 MW of 100 percent reliable capacity. This corresponds to 208,0/0,95=219,0 MW of gas turbines, OCGT. This means that 219,0 MW of additional gas turbines are needed in order to get the same average peak contribution as in the nuclear case. The cost for these are 219,0*58235+1000 = 12754 kUSD/year. The cost per produced kWh is 12754/10 kUSD/TWh = 1,275 USD/MWh.

This method only considers peak load situation and provides a size of the capacity credit difference between two sources. However:

- Only peak load situations are studied, and not all possible situations with possible challenges
- Only ten situations are used in the evaluation for both wind and nuclear.
- Only Swedish peak load is considered, while at least the Nordic system should be studied to obtain a better view.
- True calculations of capacity credit should consider the risk of capacity deficit.
- There are other methods to solve a capacity deficit situation, e.g. flexible demand which should be implemented when this solution has a lower cost. Here only one specific solution was selected.

Summary of wind power capacity credit in Sweden

The capacity credit for a certain power source is a measure of the possibility for this source to decrease the risk of capacity deficit. In order to estimate this it is necessary to have data for the availability of all power plants, load variation and interconnections between areas in the whole system. For a comparison it is important to use the same method for all types of sources.

The capacity credit is one system impact index which can be used to compare the expected performance of different alternative sources for the future power systems. All power plants have system impacts since the operation of a certain system will change when the new power plant, of any kind, starts to operate. It is important to compare available capacities corresponding to the same amount of yearly energy. The reason is that if one compare two sources that could generate W TWh/year, then it is relevant to compare the capacity credit for these two sources, i.e. the capacity credits for two sources with same yearly energy production.

One important issue is the availability of production during peak load. Here wind power and, for comparison, nuclear power availability has been studied. The result was that Swedish wind power had an average peak load contribution of 99,7 percent of yearly mean production. The corresponding figure for Swedish nuclear power was 118,0 percent.

2.5.3. Adequacy cost calculations using OCGT for a European case

During spring 2012 there was a presentation originally shown by Hubert Flocard, and later presented by a person from Statkraft (origin slightly unclear). They had studied common wind power data from Ireland, Denmark, Spain, France and Germany for a possible future situation (2030) using profiles from 2010. The result for a winter period is shown in Figure 6.

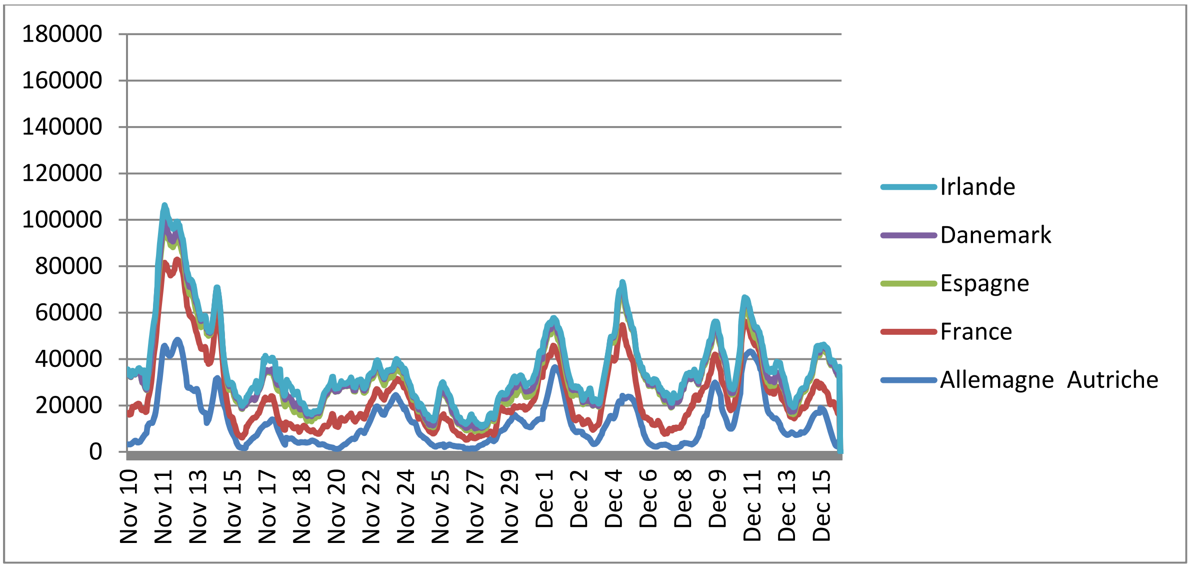

Figure 6 Wind power production, 10th November to 15th December 2030 (profile 2010). Source Statkraft + Hubert Flocard.

In the studied case the installed Capacity was 156.500 MW, and the average production was 36700 MW, or 24,8% (i.e. a capacity factor of 24,8%). The minimum production in Figure 6 is 10.850 MW ,i.e. 6,9% of installed capacity. The period was considered to be a high load situation.

Assume now that this is a representative future situation. Also assume that one would like to compare the possibility to provide capacity during high load situation with either a 100 % reliable unit or this wind power investment. Wind power then has to be compensated with 36700-10850=25850 MW. If one uses OCGT for this, then one have to pay 25850 MW*58235 USD/MW/year = 1505 MUSD/year for this. If this cost is to be spread on all wind turbines, then this cost becomes 1505 MUSD/36700 MW/8760h = 4,68 USD/MWh

2.6. Comments

As shown in the different calculations above, the capacity cost if one assumes OCGT is in the range of 1-5 USD/MWh. Using (OECD-NEA, 2012) cost estimates, this cost is then in the range of 1-5% of the investment and operation cost of the variable renewable source. But one has to consider the following:

- "Compensation" is only needed if there is really a risk of capacity deficit. The cost is zero if no extra capacity is requested.
- The whole integrated power system has to be considered when the discussion on possible need is discussed.
- Assume that the gas turbines are used only 10 hours per year. This then means that the market price has to be 58235 USD/MW /10 h = 5823 USD/MWh during these hours in order to finance the units. There are certainly a large amount of consumers who are prepared to decrease their consumption if they have to pay this price. If, e.g., consumers are prepared to do this for half the price, then the "compensation cost" decreases to 0,5-2,5 USD/MWh.
- In today's power system in the liberalized markets, one gets very high payment if one can provide power during peak load situations. If one cannot, then one will not get this high payment. This means that the "benefit of providing power in peak load situations" is already internalized in the market.

Concerning the method used in (OECD-NEA, 2012) to calculate the "adequacy back-up costs":

- It is not realistic to base any kind of market analysis or cost estimates on a method where one assumes that a market actor selects a portfolio which will not survive on the market by itself.
- The NEA method does not consider that power production higher than yearly mean from the variable source is used to decrease the fuel consumption in other sources.
- The NEA method is not based on possible system design changes from today for a future system with larger amounts of variable renewables. The cost estimation is instead based on a green-field study where one builds up the whole system without consideration of today's system. But in reality the situation we have is that we have a system today and this will be changed.

5. Balancing costs

In (OECD-NEA, 2012), page 124 it is stated: "There is no clear definition and assessment of balancing cost from dispatchable technologies: the back-up capacity (spinning reserves) and the capacity margin required in an electricity system serve for coping with different events, such as unexpected demand variations, load losses, grid failures and unplanned outages of dispatchable power plants. It is thus very difficult to directly attribute any balancing cost to a specific dispatchable technology. However, it is common practice to determine the amount of spinning reserve needed based on the size of the larger (or the two largest) power plant in the grid, which is nuclear in all six countries analysed. Based on those considerations, balancing costs have been calculated for nuclear as the costs for providing spinning reserves for a capacity equal to the differential between the largest nuclear power plant in the system and the largest non-nuclear power plant." For wind and solar power the presented results are taken from other sources, so NEA has not made any own calculations.

6. Grid connection

It is correct that for, e.g., each wind turbine there is a cost for a connection to a pint in the grid which can accept the produced power with kept power quality. However, this cost is nearly always already taken by the owner of the new power plant, e.g. a wind power plant.

The rules for payment of grid connection for Spain, Portugal, Germany and United Kingdom are handled in the Swedish government report by (Centeno-Ackermann, 2008). A summary table is presented on page 200, and shown in Table 9.

Table 5-3: Comparison of network investment costs for producers using renewable energies.

Who pays the costs for...	Sweden	Spain	Portugal	Germany	UK
Connection installations from wind farm on-shore to network connection point	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner
Connection installations from wind farm off-shore to network connection point	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Transmission Company	Independent Transmission Company (if the connection voltage is 130kV or higher)

Table 9 Summary table from (Centeno-Ackermann, 2008), page 200. It can be noted that the same rules apply to other types of power plants.

As shown in Table 9, for on-shore installations the common rule, at least in these five countries, is that the connection cost is also internalized, i.e., the wind power owner pay for them. For off-shore there is the same rule in Sweden, Spain and Portugal, but not in Germany or UK.

It can, however be noted that NEA uses the following costs for on-shore wind power, see Table 6: Finland: 107,44 USD/MWh and Germany 116,23 USD/MWh. Using 1,3 EUR/USD one get Finland: 82,65 EUR/MWh and Germany: 89,41 EUR/MWh. One should then compare this with what the feed-in tariff gives in these countries. The income for the wind power owners is for Finland 83,5 EUR/MWh (IEA Wind, 2012), page 100 and for Germany 89,3 EUR/MWh (IEA Wind, 2012), page 104. The conclusion from this is that the costs provided by NEA, for these two countries, at least include the cost for the connection which is also the standard way of handling this, see Table 9.

Concerning off-shore connections it is important to note that these often have a multi-purpose use. In (Energinet.dk, 2012) it is, e.g., stated that: "In connection with the offshore wind farm at Kriegers

Flak Energinet.dk and the German TSO (Transmission System Operator) 50Hertz Transmission plan an optimized solution for simultaneously bringing ashore current from the offshore farms, and electricity trading between the countries." This means that there is an extra value for this grid since it makes it possible to trade power between the countries.

7. Grid reinforcement and extension

The method is described on (OECD-NEA, 2012), pages 125-126. It is also stated that, page 126: "In the NEA model, no reinforcement costs are attributed to dispatchable technologies owing to the consideration that those power plants can be located in proximity the load centres".

This last statement is rather unclear and not motivated. If it was true then there should not be any transmission system in countries without solar and wind power. Especially for nuclear power one has to consider the comparatively low operating costs. Since this is so low, then these units tries to produce on maximum level as much as possible. This means that in systems with larger amounts of nuclear power it is profitable to build transmission lines to other areas so the full capacity can be used as much as possible. In addition to this there must be lines to power plants which are handling the continuous changes as well as lines to manage outages in power stations. Below two cases, France and Sweden will be shown.

7.1. Transmission expansion costs in France

Here we take France as an example. Figure 7 shows the development of the transmission grid in France, (RTE, 2006), page 12.

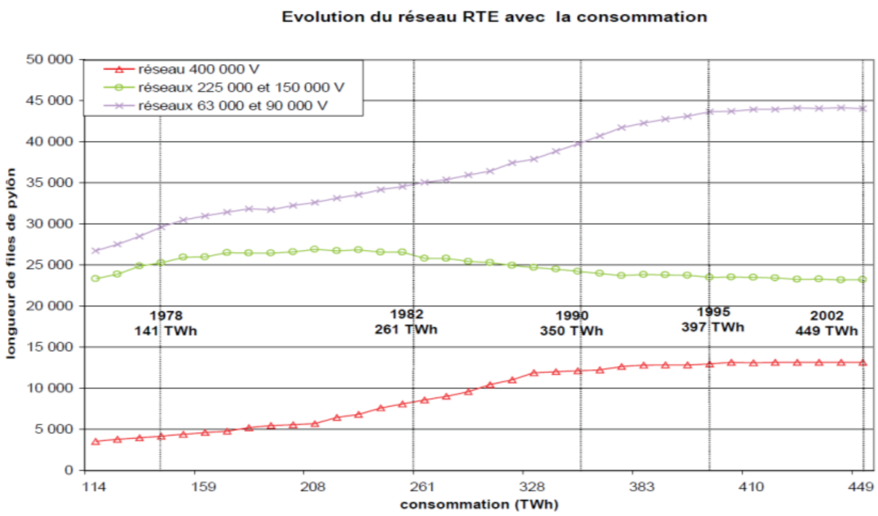

Figure 7 Development of the French transmission system

In (RTE, 2006), page 12 it is stated: "Le développement du réseau de grand transport à 400 000 V a connu use forte croissance sur une decennia à partir de la find des années 1970, accompagnant le développement de la production nucléaire", i.e. "The development of large transmission network for 400 kV has strongly grow since the end of the 1970s, accompanying the development of nuclear generation". So since 1978 to today the 400 kV network has, according to Figure 7, expanded from around 4000 km to 13000 km, i.e. 9000 km. In (ICF Consulting, 2002), page 17 (report from 2002) the costs for transmission lines is 470000-805000 EUR/km (1994 prices). Another price mentioned is 666000 EUR/km. Here we assume this last level: 666000 EUR/km, and we assume an extra investment of 8000 km, since there has also been a decrease in the length of 150-225 kV lines. The change from 1978 to 2002 in Figure 7 concerning consumption is 450-140=310 TWh/year. We here assume that this only belongs to nuclear power. The cost for the transmission lines (7% interest rate, 50 years life length) = 8000*666000/14,27 =373 MEUR/year ➔ (1,3 EUR/USD): 485 MUSD/year. This corresponds to 485 MUSD/ 310 TWh = 1,56 USD/MWh. This is then only considering the 400 kV. It must be noted that this is only the investments in France. Since France exports power, transmission investments have also been needed in the neighboring countries. The costs for the expansion of the 63 and 90 kV systems are not included here.

7.2. Transmission expansion costs in Sweden

Another case is the transmission expansion in Sweden. In (CDL - Central Operating Management, 1970), page 43 it is stated that the length of the transmission line on June 30, 1970 in Sweden was 5992 km (400 kV) and 5098 km (220 kV). On page 14 it is stated that the hydro power production during “normal conditions” should have been 53 TWh. There was no nuclear power production during this year. In (Nordel, 2003), page 35 it is stated that the length of the transmission line on December 31, 2002 in Sweden was 11067 km (400 kV) and 4628 km (220 kV). On page 36 it is stated that the nuclear power production was 65,6 TWh and on page 29 that hydro power production during “normal conditions” should have been 65 TWh. This then means an increased production in hydro and nuclear of 65+65,6-53=77,6 TWh. The 400 kV lines has increased in length with 11067-5992 = 5075 km. The length of the 220 kV lines have decreased with 5098-4628 = 470 km. We here then assume, for cost calculations, that this corresponds to an increase of 400 kV with 4800 km. Using the same costs for transmission lines as for France in section 7.1, this then gives: 4800*666000/14,27 =224 MEUR/year □ (1,3 EUR/USD): 391 MUSD/year. This corresponds to 391 MUSD/ 7,6 TWh = 3,75 USD/MWh.

7.3. Conclusions

The conclusion is that one cannot neglect transmission costs in systems with large amounts of nuclear power. Table 10 shows a comparison between the NEA method results and some comments for each figure.

10% onshore wind in Finland	From Table 1 [USD/MWh]	This analysis [USD/MWh]	Comments
Back-up costs (adequacy)	8,05	0 – 3,66	0: For the case that there is already enough capacity. OCGT compensation (3,66) is the mean value of results from Table 6 (5,01), section 2.5.2 (1,275) and section 2.5.3 (4,68). In addition to this one should also consider whether the pricing already includes this (not analyzed here)
Balancing costs	2,70	0 – 2,70	0: This is the case if the imbalance costs are already included in market pricing as well as the extra income for units as well as the extra income for controllable units participating in regulation (not analyzed here)
Grid connection	6,84	0	Should be zero since this cost is already paid by the wind power owner in Finland. This one can also see from the costs used by NEA, and the current Feed-In Tariff.
Grid reinforcement	0,20	0 – (-2,66)	The corresponding costs for nuclear power have been estimated as 1,56 USD/MWh (France in section 7.1) and 3,75

and extension			USD/MWh (Sweden in section 7.2). Finland also has comparatively large amounts of nuclear power. The mean value between France and Sweden is 2,66. Zero is motivated by that also consumers need the grid and it is not trivial to state who needs a certain part of a transmission system.
Total grid-level system costs	17,79	0 – 3,7	3,66+2,70-2,66=3,7 The higher figure, 3,7, corresponds to 3,7/107,4 = 3,4% of the NEA-cost for wind power (from Table 6)

Table 10 Comparison of the results for 10% wind power in Finland

The general result is that these costs are either comparatively small (in Finland case up to 3,4% of total cost) or already included in the market. The question is whether the market already works (or will work) in such a way that power plants that contribute to balancing and adequacy are paid for this, i.e., the "pay generator" principle, instead of the "generators pays" principle. This is, however, not yet analyzed in this report.

8. References

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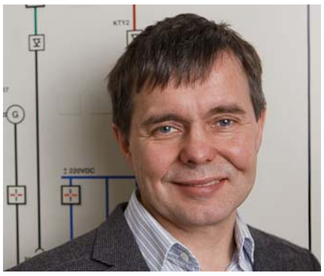
9. Biography



Lennart Söder, born 1956, is professor in Electric Power Systems at KTH since 1999. He leads a department of 40 person engaged in research and education in the field of Electric Power Systems. This includes studies of power system stability, transfer opportunities, electricity price formation, smart grid, the impact of wind and solar energy, regulation of hydropower, the effect of economic regulation, new technologies the phase angle measurements etc. Lennart Söder has participated in several national studies and he was the government's sole investigator for the Grid Inquiry: Appendix report: (Centeno-Ackermann, 2008). He is active in several international collaborative projects in Sweden, the EU and within the IEA. He has been the main supervisor for 14 PhD students who have published their PhD theses in different areas. He has taught and developed teaching compendia in the areas of "Static Analysis of power Systems", "Power system production planning" and "Electricity Market Analysis". He is the author and coauthor of more than 200 scientific papers, for details see http://kth.diva-portal.org/smash/search.jsf