Whole system impacts of electricity generation technologies

Peer review report by Lion Hirth, Neon Neue Energieökonomik GmbH

23 July 2015

Evaluation

Overall, the report is of very high quality. It is comprehensive and covers all major topics, consistent and compatible with the published literature, well structured, accessibly written, and adds significant value to the state of the art in the literature. It is likely to become one of the best reports written on the topic and can be a sound basis for the following phases of the project.

Regarding methodology, the authors seem to have comprehensively scanned the published literature (minor exceptions are pointed out below) and have involved a number of experts, both academics and practitioners. The report would benefit from listing those by name (not only the academics). The only major relevant institution that seems to be missing from the interview list is the National Renewable Energy Lab (NREL), U.S., which has published a large number of reports on the topic (e.g., Michael Milligan).

Having said this, I would like to raise a number of significant issues. Not all of these issues can be solved in the scope of this project (in some cases, entire teams of scholars have been wrestling with these issues for a decade and longer), but the report would benefit from at least flagging them or emphasizing their potential impacts. The comments are ordered by section and are loosely ranked in descending order or relevance, according to my personal judgement. I also add minor comments with reference to a specific page.

Most comments refer to the framework (section 3), which sets the basis for the rest of the analysis. Several of these are quite fundamental. I like to re-emphasize that many people have worked on a coherent and consistent framework for the past 10-15 years, and I do not expect this report (or any report) to solve all these issues at once. In general, the report would benefit from pointing out caveats with the framework and (unavoidable) inconsistency between framework and quantitative estimates.

Summary

(1) **How to use.** You need to tell the reader early in the Summary how to interpret/use the numbers (and how you will use them). How should one interpret the sum of these cost components, and the sum of system impacts and own costs? What does it mean if the sum of own costs and system costs of a technology is lower than that of another? How will *you* use the estimates? See comment (1) of the Framework section.

(2) **Size of reported costs.** I disagree with the statement that whole system impacts are "small relative to the direct costs". For wind and solar power, they can easily in the same order of magnitude as own generation costs at high penetration rates, if differences in displaced energy/capacity are included. Displaced generation cost, likely the most important category, is missing in table 3. I also have doubts about the numbers itself, which seem awkwardly high in some cases (see comment (1) regarding Section 5 below).

(3) **Benefits and costs.** The Summary would benefit from expressing more clearly what is a benefit and what is a cost, and how they relate to each other. Note that it is not always clear what is a (reduced) cost and what an (increased) benefit.
"Displaced generation cost" is always (artificial situations aside) a net benefit – in fact, it is the principle reason for generating/selling electricity at all. It should also emphasize that this benefit greatly varies among technologies and with penetration rates. In your framework, it is likely that system benefits (impacts number 4 + 5) induce larger variation among technologies than system costs (impacts number 2 +3).

(4) **Actions.** There are many things that can be done to reduce system costs, sometimes called "integration options" or "mitigation measures", ranging from improved market design to flexibility investments, system adaptation, and system-friendly wind and solar plant configuration. You should mention those, and also explain if your estimates refer to a "non-optimized" or an "optimized" power system.

Detailed comments	
page	comment
5	"Any technology which is added". Using terms like "added" or "additional" is somewhat at odds with the long-term (greenfield) timeline you apply. In a long-term perspective, you can compare a state of the world with a counterfactual state, but you cannot "add" something.
6	Table 1. Is the capacity credit reported in average or marginal terms? (Marginal would be appropriate). I recommend to leave Table 1 out of the Summary altogether, as it is a rather detailed and secondary finding.

8	You miss reduced energy value: “the three main impact categories, namely capacity adequacy, balancing, and network costs and losses.”
10	This sentence is a little unclear to me: “Generators are always incentivised to minimise their own generation costs, and hence maximise the displaced generation benefit”
11	Not only terminology and methods are different, also definitions and concepts.
11	“are by their nature very sensitive to the specific context”. Correct and helpful.
12	“dispatchable technologies and nuclear […] typically are considered part of the counterfactual and therefore have zero system impacts.” This is not true, at least not for the various publications by the IEA, Ueckerdt, and Hirth.

Further comments relevant for the summary are discussed in the respective main section of the text.

Framework / Section 3

(1) **Interpretation / use of system cost estimates**. You are very little outspoken on *how to use / interpret* the numbers that you present. Only on page 42 you state that "the literature also uses an understanding of 'system impacts' as part of an investment decision rule". Do you agree? In other words, does your framework imply the following statement? "If whole system costs of technology X are below whole system costs of technology Y, it would be beneficial to society to invest in X". If it does, please state this interpretation. If it does not, please explain (because this is how readers will interpret your numbers once they are published).
A closely related question that you should also explain: What is the *purpose* of calculating whole system costs? How will you incorporate these numbers if future assessment of technologies and modelling?

(2) **Relationship to "value of electricity"**. A related, but separated literature branch assesses many of the effects you discuss not in terms of "system costs" but rather in terms of (reduced) "value of electricity" (Grubb 1991, Lamont 2008, Joskow 2011, Mills & Wiser 2012, 2013, 2014, Nicolosi 2012, Hirth 2013, 2015, to name a few examples). It would be very helpful to understand how you see your framework related to this perspective. In fact, it might translate quite naturally in your framework, as you already discuss system benefits (displaced generation and capacity "cost"). It is key to emphasize that these benefits greatly vary among technologies, with penetration rates, and between power systems.

(3) **Ambiguity in decomposition and scope**. In my own work, I have disaggregated system costs into components, similar to you. Over the years, I have become more and more skeptical about the procedure. I still believe there is some use to it (to make the exercise less abstract, measurable, and ease communication), but I would recommend to be more cautious in wording. Often, it is not clear how to count components. (Is grid connection "own generation cost" or "grid costs"? Are balancing capacity costs part of "balancing costs" or "grid costs"?). This is also true for the separation of "plant-level", "grid-level", and "total" costs (scope, Fig 4): Are connection costs plant-level or system-level? Is curtailment plant-level or system-level? Are CO_2 costs plant-level or total? (The split might depend on the current CO_2 price).
Even worse, the categories are likely to be not independent from each other. (Shifting the optimal generation mix towards mid/peak load plants because of lower running hours might, coincidentally, also reduce balancing costs, because these plants are more flexible.) Scrubbing SO_2 might increase plant-level costs while reducing total costs.
I recommend to keep the decomposition, but flag the ambiguity in the text and avoid strong statements about comprehensiveness and non-overlap (I wish I had done so in my own writings), but emphasize ambiguity and inter-dependence.

(4) **Separating capacity and replaced energy costs.** The ambiguity in decomposition becomes very clear in the case of "replaced generation" and "capacity" cost. As you explain perfectly well (in a box), high VRE penetration reduces the utilization of the thermal plants in the rest of the system. This leads, as you explain in another box, to a different optimal generation mix. That means that the power system under consideration, when compared to the counterfactual, has a totally different CAPEX / OPEX structure. Overall capacity is likely to be reduced, but to me it is unclear how this

capacity reduction should be valued economically. It is certainly not sensible to siply evaluate this with the capital cost of a peaking plant (there is likely to be *more* peaking capacity in the system compared to the counterfactual). This is why we have not split these two components, but kept them together, labelled as “profile costs”. I recommend that you do the same; otherwise you should explain carefully how you calculate these two cost components.

(5) **Reduced cost savings.** It is a crucial aspect of VRE that, with increased penetration, they replace *less and less* generation/capacity costs. On the one hand, system costs increase with penetration (balancing, grid), but, probably more importantly, they save less and less costs (capacity and reduced energy). I am sure you are aware of this, but I recommend to explicitly mention this prominently in the report.

(6) **Curtailment**. There are two issues related to curtailment: on the one hand, curtailment of output is another area where the ambiguity becomes evident. Where do you count curtailment: Do you count it as own-generation costs (increasing the LCOE), or as grid costs (thinking of compensating plant owners for grid constraints)? Note that curtailment is a substitute for grid expansion. On the other hand, do you report system costs in $£/MWh_{potential}$ (that is, before curtailment), or in $£/MWh_{produced}$ (that is, after curtailment)? Both points need clarification.

(7) **Interaction technology – system**. System costs emerge *only* from the interaction between a technology and the rest of the power system. Imagine a world where storage and transmission would be loss-less, for free, and perfectly flexible: All system costs of all generation technologies would be zero. I recommend that you emphasize this fundamental insight: it is always a combination of a generator and a system that causes system costs. Logically, it is not possible to attribute “causality” to either one (cf. Milligan et al. 2011) A corollary of this, which you rightfully state, is that all system costs estimate *necessarily* are context-specific.

(8) **Devaluating existing assets.** The report is silent about the effect of introducing VRE on the economic value of existing plants (“stranded assets”). You use a long-term perspective, where this phenomenon is inexistent. This is a clean choice, and nothing is wrong about it. Just a warning: for policy makers (especially in France and the Western U.S., but not only there) this is often the first thing to consider when thinking about “system effects”. You might want to be prepared how to tackle such questions. Moreover, in later sections of the report you discuss short-term effects (impact on average electricity price, “compression effect) that seem to be inconsistent with your choice of a long-term timeline.

(9) **Grid analysis are not long-term**. You chose to use a long-term perspective, however, when discussing grid costs, you always refer to an existing grid. This is an inconsistency in your framework. (You are not the only one facing this problem, I am not aware of a single study that uses a true “greenfield” approach when assessing grid costs).

(10) **System impact definitions.** Your definition of system impacts is quite clear and precise. However, do you define system impacts for (a) a given level and (b) structure of (i) load and (ii) imports/exports? I think you (implicitly) do, but an explicit confirmation would be great.

(11) **Terminology.** (i) There is widespread perception that "intermittent" is a pejorative term, and also imprecise or misleading (cf. Riesz & Milligan 2015). You might wish to use the term "variable" instead.
(ii) "Grid-level impacts" is a term used in parts of the literature; nevertheless it is somewhat mislead as most impacts do not happen at the level of the grid itself, but rather within other power plants. "Power system impacts" might be more accurate.
(iii) "Own costs" are sometimes called "direct costs" (you even use this term once in the Summary). I fully admit that "direct costs" is not an intuitive term either.
(iv) You might use "system reliability" instead of "system security".

Detailed comments	
page	comment
title	Given the scope of the project, you might slightly amend the title: "Whole *power* system impacts of electricity generation technologies".
18	there are significant contributions that are older than 10 years, including the work of Michael Grubb (1991a, 1991b) and Rahman & Bouzguenda (1994
18	It would be interesting to read what you regard as the 15 key publications, as a starting point for the interested reader to dig deeper.
21 (box)	It would help to clarify two crucial decisions regarding the definition already here: Do you apply a short-term or long-term perspective (timeline) and do you apply a marginal or average approach when calculating costs?
21	In the summary of section 3, I am missing a guide how to use / interpret system costs.
21	It would be helpful to point out early that system costs are a function of (i) the technology under consideration, (ii) its market share, and (iii) the properties of the rest of the power system. This might help manage expectations of those readers who are looking for "the system costs of intermittent renewables".
23	Fig 4. The figure seems innocent and straightforward, but is problematic for two reasons: Fist, it looks as if the components were clearly separable (they are not), and as if costs (strictly) increase when widening the scope. As cost components can be negative, this is not the case.
24	Table 4. I think this table is very helpful in general. A detail: I don't see how you include "average wholesale price" and "price volatility" in your analysis. I recommend to take these out.
27	I think your definition of "whole system impact" makes sense, is rigorous, and in line with the literature. Fig 5 helps a lot illustrating the definition. Good! [see point (10) above]

27	According to your definition, what kind of technology would have no (zero) system impacts? Spelling this out might help the reader to grasp your definition.
28	Your exposition of capacity cost vs benefit is very clear and helpful.
29	What is the "counterfactual generation mix" that you assume?
30	ST and LT is often called "brownfield" vs. "greenfield". [see point (9) above]
31	Your choice of LT as an appropriate perspective makes sense and is well supported by convincing arguments.
31 (box)	This approach is quite old (Stoughton et al., 1980; Grubb, 1991; Stoft, 2002; Green, 2005), and is often called "screening curve" and "residual load duration curve" approach.
33	You might explain *why* you decompose system impacts. From an article: Our definition of integration costs can in principle be directly used in economic assessments – there is no need to disentangle integration costs into components. However, such a decomposition might be helpful for three reasons. First, it allows single components with specialized models to be estimated. Estimating total integration costs directly would require a "super model" that accounts for all characteristics and system impacts of VRE, and such a model might be impossible to construct. By contrast, estimating individual components allows using specialized models. Second, a decomposition allows the cost impact of different properties of VRE to be evaluated and compared to each other. It helps identifying the major cost drivers and prioritizing integration options (e.g., storage vs. transmission lines vs. forecast tools) to more efficiently accommodate VRE. Third, by decomposing integration costs, the new definition can be compared to the standard literature that typically calculates integration costs as the sum of balancing, grid and adequacy costs. (Hirth et al. 2015)
33	"Energy markets already recognize" – I would say "have always recognized", or even "it is at the core of electricity markets to recognize"
33	I can't see how "adequacy" costs align to power system processes.
34	Profile costs are the aggregate of what you label "capacity costs" and (declining) "replaced energy value".
34 (box)	The box explains profile costs well. However, you say that the utilization effect is described in the box above, which it really isn't. In the box above, you describe the shift of the optimal generation mix, but do not discuss the associated costs resulting from reduced utilization (even if the mix is allowed to shift optimally).
35	Fig 8. The size of the boxes might be interpreted (sub-consciously) as the relative size of the impacts. I recommend same-size boxes.
35	Fig 8. It should be "displaces *higher* marginal cost generation" (also in Summary).
36	When discussing "displaced generation costs", you must refer to (i) reduced utilization and associated costs, and (ii) a shift of the optimal generation mix that partly offsets (i). As a consequence, some fuel costs might actually increase.

36	Regarding curtailment, see (6) above.
37	When you discuss “backup”, I recommend to refer to the ST/LT-discussion on page 30.
39	This kind of variability is sometimes called “intra dispatch period variability”
39	The explanation along the tidal generator is very helpful.
39	Why do you not call “Network infrastructure, losses and congestion management” simply “grid costs”?
40	Fig 9. Are ancillary service costs included?
41	“an important question about the attribution of network costs to a specific technology” This is very true – but not only for grid costs.
41	Good example. In other words: the sequence matters (but logically, it shouldn’t). Behind this lies (9), I believe.
41	Another aspect of (distribution) networks are large economies of scale. A cable of double capacity often costs only slightly more.
42	“The literature also uses an understanding of ‘system impacts’ as part of an investment decision rule.” Do you agree? [see also (1) above]
43	Not only an investment rule for “policy makers”. If all system impacts are internalized, Fig 10 describes also what the market will deliver in the long-term equilibrium (then the inequality holds as an equality).
42	Fig 10. I think it is important to state that, with increased penetration, 4 and 5 typically increase while 2 and 3 typically decrease.

Drivers / Section 4

(1) **Capacity credit estimates.** The capacity credits reported for wind seem to be very high (Table 14), especially at higher penetration. Please verify and reference at least 2-3 other (peer-reviewed) studies (a starting point could be Ensslin et al. 2008, Amelin 2009). My intuition is that the capacity credit of additional wind power at a penetration of 30% must be almost certainly close to zero, in almost any power system.

(2) **Title.** I found the title of section 4 somewhat confusing. You do not primarily identify drivers for impacts (which are mostly system properties) and discuss how system costs could be reduced – which I expected after having read the title –, but extrapolates technological properties to other technologies. This is perfectly valid (and an important contribution to the literature), but I would use a different title. Maybe something like "Generator characteristics that determine system costs".

(3) **Storage.** At several points (e.g., p. 59) you refer to storage as decreasing system costs of a VRE technology (in this case, increasing its capacity credit) by combining a storage asset with a VRE generator. I think storage should be treated separately. The storage asset itself might have a high capacity credit, but it does not change the capacity credit of another specific asset. (Similarly, you – rightfully – do not calculate the capacity credit of a nuclear plant and a wind farm combined, but separately.)

Detailed comments	
page	comment
45	I think the box summarizes the section very well.
46	the "intrinsic, irreducible properties" of VRE can be changed, e.g. by improving weather forecasts, choosing a different location in the grid, or applying assets with higher capacity factors (low-wind speed turbines or east/west-oriented solar PV)
46	The structure of the section is well outlined. Very clear.
47	I found Table 7 very helpful.
47ff	In Table 7, 10, 13, 15, 17, and so on you always state "plant capacity" as a factor. This seems trivial and I recommend to leave it out. That is like saying "a large plant is more expensive than a small plant". True – but probably no news to your readers.
48	Table 8 misses a number of highly important system characteristics, including storage, interconnection, demand elasticity / demand response / DSM, reservoir hydro power.
49	I found Table 8 very helpful, but would like to note that "embedded" is not in line with the international terminology; more common is "distributed generation".

50	Table 10 misses a number of highly important system characteristics, including storage, interconnection, demand elasticity / demand response / DSM, reservoir hydro power.
51	"… reducing its value in terms of displaced generation costs" *to zero*!
52	Ramping / cycling costs are like to be much smaller than the impact of declining energy value.
53	"is not often quantified". This is not true. In fact, ramping/cycling are at the center of the huge U.S. debate on system costs. Compare *Western Wind and Solar Integration Study Phase 2* and *Phase 3*.
53	It seems you jump from cycling costs to the emission impact.
57	Table 12. Please double-check the numbers with further sources, such as Schröder et al. (2013) and Black & Veatch (2012).
58	The definition of capacity adequacy makes sense and is in line with the literature. Please reference.
60	The comparison of UK vs. Greece is very helpful. Could you provide the capacity credit for these two cases?
60	The statement about windy nights/days might be true for the UK, but they are not true in general.
61	The point on "Correlation with the output of other generators" is of utmost importance and merits further elaboration. A corollary of this point is that the system value of VRE declines with penetration, as different wind generators are highly correlated with each other. I recommend illustrating this point with a figure (the penetration rate being on the x-axis).
62	Capacity credit is sometimes also reported relative to the capacity factor (which I personally find more helpful).
62	The estimates for wind are implausible high [see (1) above]
63	For the non-British among your readers, it would be great to get a reference on the LOLE approach that GB applies.
65	Table 15. Another driver: correlation of forecast errors with the forecast errors of load.
66	Fig 16. You might compare to Hirth & Ziegenhagen (2015)
66	errors are not "randomly distributed" – but the correlation is less than perfect (which is sufficient to make larger balancing areas beneficial)
69	It makes sense to discuss inertia / non-synchronous generation as a sub-item under "balancing". Good choice.

74	"the associated network infrastructure is used below its technical capacity for periods of time." this is, again, the utilization effect (applied to grids rather than to plants)
74	With pollutant and noise emissions, building new coal plants within cities is likely to outright impossible. I would say, it is only gas plants that are quite unconstraint location-wise.
75	"problems due to reverse power flows." Reverse power flows by itself are not a significant problem (sometimes monitoring software requires an update)
75	Fig 21. Interesting! Could you enlarge the map to increase readability?

Cost allocation / Section 5

(1) **Report structure**. You might consider changing position of section 5 and 6: first discuss size, then allocation.

(2) **Section 5.1** is generally hard to read. You might consider rewriting it. I recommend link this to the (decreasing) value that electricity has on wholesale power markets, as the penetration rate of a technology increases [see comment (2) on section 3].

(3) **Degree of socialization.** Would you dare to provide an estimate what share of balancing costs and grid costs is internalized? Or, maybe better, to what extend the prices "seen" by investors reflect true long-term marginal costs? That would be a significant value added.

Detailed comments	
page	comment
85	The first bullet point is a great summary of the section. Clear and to the point.
85	I find this wording hard to understand (appears also in various tables, including a table in the summary): "Displaced generation costs – generators are always incentivised to minimise their own generation costs, maximising any saving. Least-cost dispatch will generally be incentivised through the energy market and so these costs can be an efficient market outcome, although they may be distorted by output-linked subsidies."
86	I find section 5.1 hard to comprehend.
86	"Displaced generation costs are best thought about as the fuel and carbon permits that no longer need to be consumed by other system generators". That is *not* the case. In the long-term perspective (that you apply), increasing the share of a technology leads to a different generation mix, with changes to both capex and opex of all generation technologies. Actually, some fuels are likely to be used *more*. It is *not* simply a reduction of fuel use.
86	Is the effect "unlikely" to be an externality, or is it certain that it is not?
87	"Note that the displacement of other generators' costs through different dispatch decisions should imply that average wholesale electricity prices fall." This happens in the short-term, but it does usually *not* happen in the long-term (which you apply).
87	On the impact of introducing VRE on consumer and producer rents, c.f. Hirth & Ueckerdt (2013)

87	I don't understand this: Does the additional generation capacity internalise these impacts? Not directly
89	Isn't the matter quite simple? If a technology does participate in the capacity market, capacity adequacy is no externality, if not, it is.
90	In the question of allocation and internalization of balancing costs, I recommend two papers: Vandezande et al. (2010) and Hirth & Ziegenhagen (2015). For concrete European examples, see ENTSO-E (2015).
90	the two bullet points summarize the issue very well
90	"In the current regime it is therefore reasonable to assume that there is an attempt within the regulations to internalise the costs of short-term balancing actions on the generator. However, this cannot be achieved perfectly" I fully agree. Well summarized.
91	Regarding grid costs, a reference to locational marginal pricing (LMP, also nodal prices) is missing. Only (!) such a pricing regime can fully internalize grid costs. Anything else (locationally differentiated grid fees) can only be a proxy. See Schweppe et al. (1988).
92	Table 19 is very useful.
93	What do you mean with "resource cost"?
93	Table 20. I am not sure if the table is terribly useful. Why do you focus on "reduced" capacity/balancing/grid costs? The argument on displaced generation seems to hold only in the ST timeline.
93	"Perhaps more important however in terms of system efficiency is the extent to which generators are incentivised to help reduce whole system costs" Yes!
94	Table 21. Very helpful. I have difficulties understanding the text in the first row (displaced generation).

Estimates / Section 6

(1) **Major concerns with the size of estimates**. You write that system costs are "relatively small" (p. 95), but then present numbers that are quite high, at least the upper bound. I think this is inconsistent.

More importantly, I have major concerns with Table 3 / 22. (i) It is not clear to which penetration levels these estimates refer. (ii) It is not clear if they represent marginal or average values. (iii) "Displaced generation costs", likely the most important category, is missing. (iv) You should guide the reader how to interpret the sum of the cost components. (v) The upper end of the balancing and grid costs are very high; likely they represent extreme assumptions or "bad practice" examples.

(2) **Missing "displaced generation"**. In the exposition of estimates (e.g., Table 3), displaced generation costs are missing, which is likely to be the largest difference between VRE technologies on the one hand and mid / peak load thermal generators on the other hand. Hirth et al. (2015) conclude: "the largest integration cost component is the reduction of utilization of the capital embodied in the power system".

(3) **Inconsistency between estimates and framework**. As said earlier, I fully subscribe to your definition of system costs on p. 27. It should be acknowledged, however, that the estimates you collect are usually not fully consistent with your framework. E.g., estimating what wind generators pay today for balancing in the UK or any other real-world power market is certainly not the same as your definition (as some costs are socialized).

(4) **Estimates without reference to penetration rate.** All types of system costs are a function of the technology's market share, as you acknowledge in the text. Displaying numbers without references to the underlying penetration rate is little informative, I would argue.

(5) **Marginal or average.** Are your estimates average or marginal system costs (i.e., the system costs of an additional unit)?

(6) **Integration options.** You should mention that there are many things that can be done to reduce system costs, sometimes called "integration options" or "mitigation measures". One reason for differences in estimates probably stems from the fact that some authors assume the current power system while others assume an "optimized" power system.

(7) **Methodology first.** I recommend moving up the subsection on Methodology to the beginning of this section. The numbers (and ranges, uncertainties, caveats) are understood much better if this is read first.

(8) **Balancing cost estimates.** Regarding balancing costs, it would be helpful to know (i) if the costs of holding reserves are included in the estimates (or only activation costs accounted for), (ii) if the estimates are cost-reflected (or based on markets where a share of costs is socialized), and (iii) if estimates represent marginal or average costs.

(9) **Summarize estimates**. The text is somewhat vague regarding the size of system costs (outside the table). Other authors have concluded that “Wind and solar integration costs are high if these technologies are deployed at large scale: […] 35-50% of generation costs. […] integration costs can be negative at low (<10%) penetration”. If you agree, readers would certainly appreciate having this spelled out. If you don’t readers would likewise appreciate to have this spelled out. Your statement that system costs are “relatively small” seems to be inconsistent with Table 3/22.

Detailed comments	
page	comment
95	“Dispatchable technologies are typically considered part of the counterfactual and therefore the costs are zero.” This is not only inconsistent with your own definition, but also with the publications by OECD, IEA, NREL, Ueckerdt, Hirth, and many others. Usually, these publications fail to report estimates for dispatchables (with the notable exception of OECD), but they emphasize that they are not zero. (Actually, in the case of peaking plants they are likely to be large and negative).
97	Figure 22. The LCOE depends on assumptions about running hours. OCGT and CCGT running hours are highly dependent on economic assumptions.
98	Figure 23 is hard to read.
100	To me, it is not clear how capacity costs is calculated in the referenced studies. Please explain. (Just adding 1 MW of gas capacity to each MW of wind capacity is nonsense).
102	Figure 23. How can capacity costs be zero? Explain how the high capacity costs for solar were calculated.
103	Sig 25. A summary statistic / trendline would help
104	Table 24. How can balancing costs for wind be zero? Please explain the high upper bound estimates.
104	“etwork costs can encompass distribution costs, transmission costs, or both”. Indeed. Moreover, sometimes connection costs are included, or not. Sometimes losses are included, or not.
106	Table 25. The grid costs for VRE are extraordinarily high. The upper bounds are likely they represent extreme assumptions or “bad practice” examples that can be easily avoided (such as placing large amounts of solar in an already overloaded remote part of the distribution grid). The lower bound of solar PV grid costs is definitively wrong. I am aware of at least one study (Pudjianto et al. 2013) that reports negative grid costs for solar PV, at least in the case of Greece.
107	“Many of the approaches summarised are consistent with the framework we have set out in the previous section.” I doubt this. [see (3) above].

107	“What emerges from Table 26 is the near impossibility of consistently comparing cost estimates across sources. […] it is not possible to provide one single estimate of current system costs from looking at the literature in this way.” I couldn’t agree more. Thank you for stating this so clearly. It would help the reader to see this before digging through the numbers [see (6) above].

References of the report

Detailed comments	
page	comment
114	Outdated reference. Use this one: Gowrisankaran, Gautam, Stanley S. Reynolds & Mario Samano (2015): "Intermittency and the Value of Renewable Energy", *Journal of Political Economy (forthcoming).*
114	Outdated/double reference. Hirth (2012) "Integration costs" and Hirth et al. (2015) "Integration costs" is the same (updated) publication.
114	Double reference. Hirth (2013) is named twice.
115	Outdated reference. Use this one: Keyaerts, Nico, Erik Delarue, Yannick Rombauts & William D'haeseleer (2014): "Impact of unpredictable renewables on gas-balancing design in Europe", *Applied Energy 119*, 266-277.
115	Outdated reference. Use this one: Nagl, Stephan & Dietmar Lindenberger (2013): "The Costs of Electricity Systems with a High Share of Fluctuating Renewables - A Stochastic Investment and Dispatch Optimization Model", Energy Journal 34(4), 151-179.
116	Double reference. Von der Bergh et al. (2013) is named twice,.

References used in this review

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