Elsevier Editorial System(tm) for Energy
Manuscript Draft

Manuscript Number: EGY-D-10-00940R1

Title: Sustainability and reliability assessment of microgrids in a regional electricity market

Article Type: Special Issue: ECOS 2010

Keywords: Microgrids; sustainability; reliability; Northwestern Europe; exergy; economics

Corresponding Author: Miss Chiara Lo Prete,

Corresponding Author's Institution: Johns Hopkins University

First Author: Chiara Lo Prete

Order of Authors: Chiara Lo Prete; Benjamin F Hobbs; Catherine S Norman; Sergio Cano-Andrade; Alejandro Fuentes; Michael R von Spakovsky; Lamine Mili

Abstract: We develop a framework to assess and quantify the sustainability and reliability of different power production scenarios in a regional system, focusing on the interaction of microgrids with the existing transmission/distribution grid. The Northwestern European electricity market (Belgium, France, Germany and the Netherlands) provides a case study for our purposes. We present simulations of power market outcomes under various policies and levels of microgrid penetration, and evaluate them using a diverse set of metrics. This analysis is the first attempt to include exergy-based and reliability indices when evaluating the role of microgrids in regional power systems. The results suggest that a power network in which fossil-fueled microgrids and a price on CO2 emissions are included has the highest composite sustainability index.

July 2nd, 2011

Sustainability and reliability assessment of microgrids in a regional electricity market

Response to the reviewers

We thank the reviewers for their helpful suggestions concerning our paper. Below are our responses ("R") to the questions that have been raised, and summaries of the manuscript changes we made in response. Our responses are bolded, while text inserts or changes are *italicized*. We have made substantial changes, including simulation of several new scenarios involving renewable-based MG, among others, and additions of text on issues of power quality and social sustainability. We look forward to the referees' and editor's further comments.

Reviewer #1:

1) Original Text:

"A microgrid (MG) is a localized grouping of loads, generation and storage that can operate in parallel with the electricity grid or in island mode and can be supplied by renewable and/or fossil-fueled distributed generation."

Reviewer's comment (p.1, c.1, r.33): to be precise, "electric" should be added here, or is also the thermal demand considered (but in this case, it cannot be satisfied by the electricity grid)?

R: A microgrid can include thermal loads as well. One of the advantages of a microgrid configuration would be local provision of heat, which would avoid inefficient heat transport over long distances. This is the case in our scenarios, where heat and electricity are provided locally by Combined Heat and Power generating technologies. In the revised version of the paper, we have changed our microgrid definition to the following: "*A microgrid (MG) is a localized grouping of electric and thermal loads, generation and storage that can operate in parallel with the grid or in island mode and can be supplied by renewable and/or fossil-fueled distributed generation.*"

2) Original Text:

"The function of multi-criteria analysis is to communicate tradeoffs among conflicting criteria and to help users quantify and apply value judgments in order to recommend a course of action."

Reviewer’s comment (p.1, c.1, r.51): we come here to the old debate about the fact that if tradeoffs between criteria is possible, this explicitly means that there is necessarily a common metric between these criteria, ... therefore the problem is no more of a true multi-criteria nature strictly-speaking (see LAMSADE, Bernard Roy's, publications) !

R: We are uncertain about what kind of response the reviewer expects since the purpose of our paper is not to continue or try to resolve this on-going “old debate”. The statement above which appears in the paper is correct and the debate of whether or not the term “multi-criteria” should be used is not germane to our paper. Certainly one can argue that variables expressed in different units (e.g., cost, energy/exergy, species mass, etc.) and representing different conflicting criteria will drive the synthesis, design, and operation of a given system in different directions. That they can be traded off against one another by reducing them to a common metric (i.e., via use of a set of weights or conversion to a single type of unit) is a given. Whether or not that requires that this be classified as multi-criteria or single criterion is, as pointed out by the reviewer, a matter of debate.

We now point out in Section 1 that a single objective optimization model (the market simulation model, subject to a CO_2 constraint) is used to generate the values of most of the criteria that are used in the multi-criteria analysis. We hope that this will clarify the role of the multi-criteria and single objective analyses.

3) Original Text:

“ …. (We do not consider social sustainability) because of the lack of suitable data on social sustainability impacts and because there is no strong evidence to believe that these impacts would vary significantly enough to drive results.”

Reviewer’s comment (p.1, c.2, r.51): I don't fully agree; there are multiple examples showing that the public opinion perception of a technology (a "social" factor to my opinion) is often the decisive factor influencing decisions.

R: The reviewer makes a good point; social sustainability is important in many energy contexts. Therefore, in the revised version of the paper, we discuss this aspect in greater detail in Section 1 and conduct a numerical sensitivity analysis in Section 5.

We consider several impact areas that are commonly cited as important for social sustainability: equity, community impacts, level of participation in decision making, and health impacts. The first three of these depend heavily on how a given microgrid is owned and managed. In general, it is plausible that the increased involvement of members of the microgrid-served population in ownership and management decisions, relative to populations served by conventional utilities, counts as a positive impact on social

sustainability. Additionally, shared community values may lead some stakeholders to value microgrids that use renewable energy more highly than either microgrids that do not or larger systems in which the community has little choice about the source of electricity (see, for example, Maruyama et al. 2007). Increased security of supply associated with microgrids may also offer social as well as economic benefits within and outside the community served by a microgrid. Finally, microgrid operation may create jobs that offer social sustainability gains for the local community.

On the other hand, microgrids may have negative effects on residents' quality of life, if they increase the level of noise or have aesthetic impacts on the landscape (Gallego Carrera and Mack, 2010). Health impacts of a microgrid may also be negative, as microgrids are likely to have generation and thus pollution closer to the populations they serve than conventional distribution networks. How risks to life and health associated with local air pollution compare with the ones from a conventional utility source will be very population, site and technology specific.

While we can speculate on the likely direction of these impacts for the power systems modeled in the paper, it is difficult to quantify them without reference to a specific population whose views and willingness to pay can be surveyed or estimated. The methodology used in our analysis aims instead at assessing the broader impacts of alternative power generation paths on a regional power system. For this reason, no direct quantification of social sustainability is offered in our study.

However, to assess whether social sustainability considerations could change the outcome of the analysis, we have included a sensitivity analysis on the normalized values of the indicators. The goal is to assess how the introduction of a generic social sustainability sub-index might alter the results presented in our analysis, if all criteria (environmental, economic, efficiencies, reliability and social) were equally weighted. It turns out that even a terrible performance of the best scenario on the social sustainability indicator (i.e., a normalized value of the social sustainability indicator equal to zero in the best scenario) would not be enough to dislodge this alternative from its top spot. Therefore, the inclusion of a social sustainability index would not significantly alter the results of this paper. These results are shown in new Table 12 and discussed in Section 5 of the revised paper.

4) Original Text:

"The first set of indices is based on CO_2 and conventional air pollutant emissions (NO_x and SO_x)."

Reviewer's comment (p.1, c.2, r.60): It should be noted here that pollutant emissions for fossil-fueled systems are generally directly related to the CO_2 emission; therefore they cannot (an should not!) be considered as independent criteria, in order to not biased the results.

R: CO_2, NO_x and SO_x emissions are distinct pollutants with distinct impacts. The total pollution impact is not unreasonably summarized as the sum of their contributions. The first pollutant is a greenhouse gas, which is thermodynamically directly proportional to the efficiency of production, while the other two are 'conventional' air pollutants, which are not. Furthermore, while the effects of the first one are global in scale, the ones of NO_x and SO_x are mostly local or regional. Conventional air pollutant emissions are not necessarily directly related to CO_2 emissions; for instance, our data base contains highly efficient (low CO_2) gas-fired plants that also happen to have higher NO_x emissions than some less efficient gas plants. As a particular example, consider the emission rates of natural gas micro-turbines and diesel reciprocating engines operating in the microgrid, detailed below in Table 5 in Section 4.1.

Table 5: Emission rates in the MGs by technology

Technology	CO_2	NO_x	SO_x	Source
SOFCs	0.51	-	-	[51]
Gas MTs	0.70	0.000068	0.000003	[52]
Diesel REs	0.65	0.00991	0.000206	[53]

Note: emission rates are in ton/MWh power generated.

While the CO_2 emission rate per MWh produced is slightly higher for the microturbine than for the reciprocating engine, the NO_x and SO_x emission rates of the former are much lower than the ones of the latter. We do not believe the introduction of three separate criteria to measure the environmental performance of our scenarios biases the results.

5) Original Text:

"The second (set of indices) emphasizes economic sustainability in terms of total generation costs and accounts for externalities of electricity generation."

Reviewer's comment (p.2, c.1, r.3): I have the greatest doubt that external costs could be objectively and completely evaluated; moreover, they will duplicate other criteria, particularly the environmental ones, and thus again be redundant in a multi-criteria analysis, which will biased the results.

R: This is an important point; counting both the external costs of pollution in the cost indices and emissions as separate pollution indices could be viewed as double counting. To

account for this possibility, we have performed a sensitivity analysis on our results. We calculated the values of the composite sustainability index disregarding Indicator 5 (i.e., we only considered Indicator 4 in the economic sub-index). Even in this case, a scenario including fossil-fueled MGs and a price on CO_2 emission allowances represents the best alternative. These results are shown in new Table 12 in Section 5 of the revised paper.

6) Original Text:

“We consider thermodynamic definitions of sustainability because an analysis relying on first law efficiency alone does not consider to what degree the outputs of a power plant are useful”.

Reviewer’s comment (p.2, c.1, r.27): "exergy"? First Law alone is also part of thermodynamics.

R: In the revised version of the paper, we have rephrased for greater clarity as follows: *“We include exergy because an analysis relying on first law efficiency alone does not consider to what degree the outputs of a power plant are useful”.*

7) Original Text:

“For example, electricity is more valuable than low pressure and temperature steam, one of the typical by-products of power production, because the latter is characterized on a per unit energy basis by a lower value of exergy than the electricity.”

Reviewer’s comment (p.2, c.1, r.31): even high pressure and temperature steam is less valuable than electricity!

R: We agree with the reviewer. In the revised version of the paper we have rephrased as follows: “*…electricity is more valuable than steam, one of the typical by-products of power production, because the latter is characterized on a per unit energy basis by a lower value of exergy than the electricity*.”

8) Original Text:

“We do not consider aspects of power quality (such as voltage stability) that may also be controlled within MGs.”

Reviewer’s comment (p.2, c.2, r.15): this is however a very important aspect of the implementation of decentralised generation systems.

R: We agree with the reviewer on the potential importance of power quality. It has been argued that microgrids have the potential to deliver different degrees of power quality tailored for different customers' needs, as they may be employed to control power quality locally according to customers' requirements. This may prove to be more beneficial than providing a uniform level of quality and service to all customers, without differentiating among their needs (see Marnay, 2008; Chowdhury, et al., 2009). However, the way in which microgrids may affect power quality in a regional grid is still under study and there are no definitive results. For this reason, we did not include power quality considerations in our analysis. This issue is discussed in Section 1 of the revised paper.

9) Original Text:

"The groups of MGs are connected to the transmission system by radial links at nodes Krim, Maas and Zwol in the Netherlands."

Reviewer's comment (p.3, c.1, r. 5): why only in the Netherlands?

R: This is just an assumption made in the analysis. We are focusing on the impact of new microgrids in the Netherlands, but to understand their impacts on the regional power grid it is necessary to consider the neighboring countries' bulk power markets. Of course, groups of microgrids could also be connected to nodes in other countries. However, we would then need to consider additional neighboring countries, such as Poland or the Iberian peninsula. This issue is clarified in Section 2.1 of the revised paper.

10) Original Text:

"Hourly loads are organized in load duration curves (LDCs) and divided into six blocks: the first block averages the load of the first 100 hours, the second block of the following 900 hours, the third and fourth of the next 2,500 hours, the fifth of the next 2,284 hours, the sixth of the last 500 hours."

Reviewer's comment (p.3, c.2, r. 55): why are there 24 hours more than during one "normal" year? is it a leap year?!

R: yes, 2008 was a leap year. This is clarified in Section 2.1.2 in the revised paper.

11) Original text:

"It is difficult to assess the overall performance of the scenarios if each indicator is expressed in different units."

Reviewer’s comment (p.6, c.2, r. 48): but this is precisely what "true multi-criteria analysis" is all about.

R: The reviewer is correct. As pointed out by the reviewer in comment 2) above and agreed to in our response, a common metric is needed to do the tradeoff. So we have modified the sentence as follows: "*It is difficult to assess the overall performance of the scenarios if each indicator is expressed in different units; this is the central challenge posed by multi-criteria decision problems*."

12) Original text:

“We calculate a sub-index for each group, obtained as the average of the indicators in the group. Each indicator is equally weighted. Finally, we aggregate our results in a composite sustainability index to gauge the overall performance of each scenario. The composite index is a simple average of the four sub-indices. If all sub-indices are given equal weights, a power network including MGs and a price on CO_2 emission allowances has a composite sustainability index that is more than double the one of a scenario excluding both.”

Reviewer’s comment (p.7, c.1, r. 13): all these assumptions and "tricks" look quite arbitrary to me, and the general "weighted sum" approach used here is not a "real" multi-criteria approach (again, see Roy's publications).

R: It is unclear which assumptions or ‘tricks’ the reviewer is referring to. The paragraph above simply describes the methodology employed to calculate the sustainability index. On the other hand, the weighted sum approach has been widely used in multi-criteria decision analysis. See, for example, Wang et al., 2009; Belton and Stewart, 2002; Triantaphyllou, 2000; Athanassopoulos and Podinovski, 1997. It is in fact the most common multicriteria method used in energy applications (see Hobbs and Meier, 2000). Ideally, the approach should be based on elicited value judgments by stakeholders, but this was not possible in the scope of this study; however, we discuss how this can be done, and the calculations shown illustrate how this method can be applied.

It is true that some of the literature of multi-objective methods refers to the type of methods developed by Bernard Roy and his followers (such as ELECTRE) as multi-criteria methods, as opposed to the US-UK school (Raiffa etc.) which are sometimes differentiated as multi-attribute methods. However, here we refer to the broader sense of multi-criteria methods as in, e.g., Belton and Stewart’s definitive 2002 textbook, which encompasses both.

13) Original text:

“Our implicit equal weighting may, of course, not be appropriate, depending on societal willingness-to-pay for emission reductions, cost reductions, efficiency improvements and reliability.”

Reviewer’s comment (p.7, c.1, r. 15): why "implicit"? this assumption seems quite explicit in the calculations.

R: By “implicit equal weighting” we meant that, for a given set of weights (equal weights in our analysis), choice of scale results in different implicit weights (or marginal rates of substitution). Therefore, any choices made about scale and about weights (even 'no' weights, or equal weights) imply a marginal rate of substitution. In the revised version of the paper, we have rephrased the sentence above, avoiding the word “implicit” for greater clarity. The new sentence in Section 5.2 is *“Our equal weighting may, of course, not be appropriate, depending on societal willingness-to-pay for emission reductions, cost reductions, efficiency improvements and reliability.”*

14) Original text:

“In all cases the ranking of scenarios shown in Table 10 is unchanged.”

Reviewer’s comment (p.7, c.1, r. 21): which looks a little surprising to me and not necessarily convincing of the appropriateness of the approach.

R: This sentence was badly phrased. What we meant is that in all cases the best alternative was Scenario 4 (Scenario 5 in the revised version of the paper). We have rephrased this sentence for greater clarity in Section 5.2: *“We assign more weight to each dimension (environmental, economic, technical and reliability) in turn. In all cases, Scenario 5 (fossil-fueled MGs and a price on CO_2 emission allowances) continues to represent the best alternative. However, the ranking of the other alternatives is different, depending on which dimension is given more or less weight.”*

Reviewer #2:

Interesting subject, well written.

1)

Reviewer's comment: please provide evidence, that there is a "Northwestern European electricity market".

R: Since 2006, the electricity exchanges of the Netherlands (APX), France (Powernext) and Belgium (Belpex) have been coupled (Trilateral Market Coupling, or TLC). Market coupling has created an integrated electricity market and represented a key step towards the integration of the northwest European electricity market, ensuring the collaboration of the three national TSOs – TenneT, Elia and RTE.

In 2007, representatives of the national governments of the Netherlands, Belgium, France, Germany and Luxembourg, their regulatory authorities, the electricity exchanges and the grid operators signed a statement of intent regarding electricity market coupling and security of supply in northwestern Europe. The intention was to add two new countries – Germany and Luxembourg – to the TLC, to realize market coupling within the five countries and to promote further integration of Europe's largest regional electricity market. In November 2010, the TLC was replaced by the Central Western European Market Coupling (CWE) and linked to the existing market coupling of Germany and Denmark (European Market Coupling Company).

Further details on the integration of these regional markets are offered in the following publications:

http://www.clingendael.nl/publications/2010/201005_CIEP_Energypaper_JJong_PBoot_BBuijs.pdf

http://www.tennettso.de/pages/tennettso_en/Press/Information_Material/PDF/100478_TEN_Brochure_marktkoppeling.pdf

http://www.apxendex.com/index.php?id=186

These developments are briefly mentioned in Section 1 of the revised paper, and a citation provided. The new sentence is: *"The setting is the Northwestern European electricity market (Belgium, France, Germany and the Netherlands). This is a regional network whose national markets already influence each other strongly and have taken steps to integrate even further into a single market. Since 2006, for example, the Netherlands, France and Belgium have coupled their electricity exchanges through the Trilateral Market Coupling (TLC), ensuring the convergence of spot electricity prices in the three countries. In November 2010, the TLC*

was replaced by the Central Western European Market Coupling (CWE), which also includes Germany."

2) Original text:

"....because of the lack of suitable data on social sustainability impacts and because there is no strong evidence to believe that these impacts would vary significantly enough to drive results".

Reviewer's comment: I disagree on both arguments. Either you include social indicators somehow, or you change the subject, because a sustainability assessment without social factors is kind of cheating. Have a look at e.g. "Gallego Carrera & Mack, Energy Policy 38(2010)1030-1039."

R: The reviewer makes a good point; social sustainability is important in many energy contexts. Therefore, in the revised version of the paper, we discuss this aspect in greater detail in Section 1 and conduct a numerical sensitivity analysis in Section 5.

We consider several impact areas that are commonly cited as important for social sustainability: equity, community impacts, level of participation in decision making, and health impacts. The first three of these depend heavily on how a given microgrid is owned and managed. In general, it is plausible that the increased involvement of members of the microgrid-served population in ownership and management decisions, relative to populations served by conventional utilities, counts as a positive impact on social sustainability. Additionally, shared community values may lead some stakeholders to value microgrids that use renewable energy more highly than either microgrids that do not or larger systems in which the community has little choice about the source of electricity (see, for example, Maruyama et al. 2007). Increased security of supply associated with microgrids may also offer social as well as economic benefits within and outside the community served by a microgrid. Finally, microgrid operation may create jobs that offer social sustainability gains for the local community.

On the other hand, microgrids may have negative effects on residents' quality of life, if they increase the level of noise or have aesthetic impacts on the landscape (Gallego Carrera and Mack, 2010). Health impacts of a microgrid may also be negative, as microgrids are likely to have generation and thus pollution closer to the populations they serve than conventional distribution networks. How risks to life and health associated with local air pollution compare with the ones from a conventional utility source will be very population, site and technology specific.

While we can speculate on the likely direction of these impacts for the power systems modeled in the paper, it is difficult to quantify them without reference to a specific

population whose views and willingness to pay can be surveyed or estimated. The methodology used in our analysis aims instead at assessing the broader impacts of alternative power generation paths on a regional power system. For this reason, no direct quantification of social sustainability is offered in our study.

However, to assess whether social sustainability considerations could change the outcome of the analysis, we have included a sensitivity analysis on the normalized values of the indicators. The goal is to assess how the introduction of a generic social sustainability sub-index might alter the results presented in our analysis, if all criteria (environmental, economic, efficiencies, reliability and social) were equally weighted. It turns out that even a terrible performance of the best scenario on the social sustainability indicator (i.e., a normalized value of the social sustainability indicator equal to zero in the best scenario) would not be enough to dislodge this alternative from its top spot. Therefore, the inclusion of a social sustainability index would not significantly alter the results of this paper. These results are shown in new Table 12 and discussed in Section 5 of the revised paper.

3)

Reviewer's comment: you refer to ExternE concerning externalities. However, that's not state of the art anymore; the latest EU project (as a follow up of ExternE) on externalities was NEEDS, see http://www.needs-project.org/ and http://www.needs-project.org/2009/. Please use these results for calculating the externalities in your study.

R: We had previously considered employing some of the tools developed in the framework of the NEEDS project (in particular EcoSense Web) to evaluate the external costs of NO_x and SO_x. EcoSense allows estimation of external costs of energy technologies by taking account of specific, context dependent variables (geography, population density, etc.). In the context of our analysis, however, we do not make reference to specific sites of each of the many power plants whose output changes in at least one period in the market solutions. Furthermore, we do not have information on the technical parameters of all power plants modeled in our regional system (e.g., stack gas exit velocities), which would be needed as inputs to the EcoSense software. In the ECN database groups of power plants are aggregated into steps of supply functions at each node of the network, and only general characteristics of each step (e.g., aggregate capacity, average efficiency) are available. Therefore, it is not possible to calculate the external costs of SO_x and NO_x using EcoSense Web due to lack of technical data. We clarify the aspect mentioned above in Section 4.2 and point out in Section 6 that estimation of external costs accounting for specific, context dependent variables might be a useful future extension of our regional assessment methodology.

Furthermore, in line with the recommendation of the reviewer, in the revised version of the paper we refer to the updated external costs on human health from power plant combustion ("SNAP sector 1") provided in one of the public reports of the NEEDS project (RS3a-D1.1, "Report on the procedure and data to generate averaged data" http://www.needs-project.org/2009/). The values we refer to are average generalised values per country, in euro/ton emission, for the year 2008.

The EcoSense software does not calculate the damage and external cost due to CO_2, as this is not considered a pollutant but a greenhouse gas. In the revised version of the paper we refer to the external cost of CO_2 given in Frangopoulos and Keramioti (2010).

External environmental costs (OLD)

1995 ECU/ton(1ECU=1 Euro)

	CO2	NOx		SO2	
		Coal/Oil	Gas	Coal/Oil	Gas
Belgium	32	13036	13053	12141	-
France	32	17100	17100	11000	-
Germany	32	4214	4214	9732	-
Netherlands	32	5480	5916	7581	-

Source: Vol.10, http://www.externe.info/, 1999

External environmental costs (NEW)

euro/ton

	CO2	NOx	SO2
Belgium	19	5707	8048
France	19	6513	6286
Germany	19	6897	7787
Netherlands	19	5172	7704

For NOx and SO2, source: Report RS3a-D1.1,
http://www.needs-project.org/2009/
"Report on the procedure and data to generate averaged/aggregated data", 2008
For CO2, source: Frangopoulos and Keramioti, 2010

4)

Reviewer's comment: including renewable generators would significantly increase the relevance of your work.

R: This is a good point. The ECN database does not include renewable generators (except for hydro) except only as a net offset to demand; as a result, we cannot include these generators explicitly in the scenarios excluding microgrids.

We can assume, however, that renewable generators account for part of the generating capacity installed at the microgrid level. In the revised version of the paper we have added additional analyses in the form of two scenarios in which 20% of microgrid generating capacity is provided by solar photovoltaics and stored in batteries, instead of solid oxide fuel cells. The new scenarios are described in Section 3 in the revised paper.

5)

Reviewer's comment: as far as I can see, you're not including any life cycle considerations, i.e. you only include direct emissions from operation of power plants, but not those of fuel production, transport, processing, etc., i.e. not complete energy chains. From a sustainability point of view, this is problematic. You have to justify this simplification in a convincing way.

R: This is a good point. In the revised version of the paper, we have considered an estimate for the emissions of the complete fuel chain for nuclear, coal and natural gas power plants. These technologies account, respectively, for 44%, 31% and 16% of total generating capacity in our regional system. Additionally, coal and natural gas fired capacity represent about 97% (94%) [89%] of total CO_2 (NO_x) [SO_x] emissions from power generation in the regional grid.

In our analysis, we increase the emissions from coal and natural gas generators to account for emissions in the fuel production, transport, and disposal portions of the fuel cycle. This is done using values indicated by two National Renewable Energy Laboratory reports ("Life cycle assessment of coal-fired power production" -http://www.nrel.gov/docs/fy99osti/25119.pdf- and "Life cycle assessment of a natural gas combined cycle power generation system" -http://www.nrel.gov/docs/fy00osti/27715.pdf-) and detailed below.

Average air emissions per kWh of electricity produced

Coal power plant

	System total emissions (in g/kWh)	% of total from surface coal mining	% of total from transportation	% of total from electricity generation
CO2	1020.00	0.9%	1.7%	97.3%
NOx	3.35	1.4%	5.5%	93.1%
SOx	6.70	1.1%	1.4%	97.5%

Source: NREL, Life cycle assessment of coal-fired power production, 1999. Table 25

Natural gas power plant

	System total emissions (in g/kWh)	% of total from construction and decommissioning	% of total from natural gas production and distribution	% of total from ammonia production and distribution	% of total from electricity generation
CO2	440.00	0.5%	15.0%	0.1%	84.4%
NOx	0.57	1.6%	81.5%	0.1%	16.7%
SOx	0.32	15.4%	83.8%	0.2%	0.6%

Source: NREL, Life cycle assessment of a natural gas combined cycle power generation system. 2000. Table 8.

These values are corrected for the heat rates of different power plants (so that a less efficient gas plant results in more emissions than a more efficient plant).

For nuclear power plants, we include CO_2, NO_x and SO_x emissions calculated on a life-cycle basis, based on the average values given by British Energy in 2005 for its Torness nuclear power stations. Emissions in g/kWh of electricity generated are detailed below.

Nuclear power plant

	g/kWh
CO2	5.05
NOx	0.01
SOx	0.019

Source: Environmental Product Declaration of electricity from Torness Nuclear Power Station
British Energy, 2005

This addition is described in Section 4.1 in the revised paper.

6) Original text:

"In Scenarios 2 and 4 the only pollutant emissions considered are due to the power plants operating in the network."

Reviewer’s comment: You do have pollutant emissions from the MG as well, right?

R: Yes. We just meant that no emissions from boilers are included in Scenarios 2 and 4 (now Scenarios 2 and 5 in the revised version of the paper), as the heat requirement of the network is entirely provided by the CHP technologies installed at the microgrid level. We have clarified this in the revised version of the paper (Section 4.1). The new sentence is *“… in Scenarios 2 and 5 the only pollutant emissions considered are due to the power plants operating in the network. There are no emissions from boilers in this case, as the heat requirement of the microgrids is entirely provided by their CHP technologies.”*

7)

Reviewer’s comment: In table 3 the emission rate of natural gas is too high: modern CC power plants have CO_2 emission factors below 0.4 ton/MWh.

R: The emission rates indicated in Table 3 (now Table 4 in the revised version of the paper) do not refer to modern natural gas combined cycles only, but are averages of different types of existing natural gas power plants in the power generating park of the four countries. The existing capacity is dominated by less efficient steam plants. For this reason, the average emission rate is higher than the one the reviewer mentions. This point is now made in Section 4.1 of the paper in the new sentence: *“It is worth emphasizing that the emission rates shown in Table 4 do not refer to modern plants only, but are averages of different types of existing plants in the power generating park of the four countries. The existing capacity is dominated by less efficient steam plants.”*

In the revised version of the paper, we have also used more accurate emission rates for microgrid technologies (Table 5).

8)

Reviewer’s comment: In Tables 3 and 4 is the unit ton per MWh electricity generated? If yes, please specify explicitly.

R: Yes. We have clarified this in Tables 4 and 5 in the revised version of the paper.

9)

Reviewer's comment: In Section 2.4.2, it seems you're only considering the costs of units potentially replaced by MG. What about the rest of generation capacities? Why don't you compare the complete systems?

R: The reason is that the costs of the remaining part of the electric system will be the same in all scenarios. They represent a fixed cost in all scenarios, and therefore can be disregarded, since they won't affect the differences among the systems, which is what determines the ranking of the scenarios. We have clarified this point in Section 4.2.: ***"We only consider the cost of units potentially replaced by MGs, as the one of other units represents a fixed cost in all scenarios, and therefore can be disregarded, since it won't affect the differences among the systems, which is what determines the ranking of the scenarios."***

10)

Reviewer's comment: please provide more information on the composition of your generation capacities, i.e. shares of individual fuels and technologies, for all 4 scenarios. Otherwise, i.e. currently, your results are not transparent.

R: in the revised version of the paper, we have included a table detailing the share of generation capacities in the three main scenarios (no microgrids; microgrids – fossil fuels only; microgrids – fossil fuels and PV). This is Table 3 in the revised version of the paper.

References

Maruyama, Y., Nishikido, M., Iida, T. 2007. The rise of community wind power in Japan: Enhanced acceptance through social innovation, Energy Policy, 35(5), p. 2761-2769.

Gallego Carrera, D., Mack, A. 2010. Sustainability assessment of energy technologies via social indicators: results of a survey among European energy experts. Energy Policy 38, p. 1030-1039.

Marnay, C. 2008. Microgrids and heterogenous power quality and reliability. Lawrence Berkeley Laboratory working paper.

Chowdhury, S., Chowdhury, S.P., Crossley, P. Microgrids and active distribution networks. The Institution of Engineering and Technology; 2009.

Wang, J., Jing, Y., Zhang, C., Zhao, J. 2009. Review on multi-criteria decision analysis aid in sustainable energy decision making. Renewable and sustainable energy reviews 13, p. 2263-2278.

Belton, V., Stewart, T.J. Multiple criteria decision analysis. Kluwer Academic Publications; 2002.

Triantaphyllou, E. Multiple criteria decision making: a comparative study. Kluwer Academic Publications; 2000.

Athanassopoulos, A.D., Podinovski, V.V. 1997. Dominance and Potential Optimality in Multiple Criteria Decision Analysis with Imprecise Information. The Journal of the Operational Research Society, 48(2, p. 142-150.

Hobbs, B.F., Meier, P. Energy decisions and the environment: a guide to the use of multicriteria methods. Kluwer Academic Publishers; 2000.

Frangopoulos, C.A., Keramioti, D.E. Multi-criteria evaluation of energy systems with sustainability considerations. Entropy 2010; 12(5): 1006-20.

Sustainability and reliability assessment of microgrids in a regional electricity market

Chiara Lo Prete[a,*], Benjamin F. Hobbs[a], Catherine S. Norman[a], Sergio Cano-Andrade[b], Alejandro Fuentes[b], Michael R. von Spakovsky[b], Lamine Mili[c]

[a] *Johns Hopkins University, Department of Geography and Environmental Engineering, Baltimore, USA*
[b] *Virginia Polytechnic Institute and State University, Department of Mechanical Engineering, Blacksburg, USA*
[c] *Virginia Polytechnic Institute and State University, Department of Electrical and Computer Engineering, Blacksburg, USA*

Abstract

We develop a framework to assess and quantify the sustainability and reliability of different power production scenarios in a regional system, focusing on the interaction of microgrids with the existing transmission/distribution grid. The Northwestern European electricity market (Belgium, France, Germany and the Netherlands) provides a case study for our purposes. We present simulations of power market outcomes under various policies and levels of microgrid penetration, and evaluate them using a diverse set of metrics. This analysis is the first attempt to include exergy-based and reliability indices when evaluating the role of microgrids in regional power systems. The results suggest that a power network in which fossil-fueled microgrids and a price on CO_2 emissions are included has the highest composite sustainability index.

Keywords: Microgrids, sustainability, reliability, Northwestern Europe, exergy, economics, air pollution, multi-criteria decision making.

1. Introduction

A microgrid (MG) is a localized grouping of electric and thermal loads, generation and storage that can operate in parallel with the grid or in island mode and can be supplied by renewable and/or fossil-fueled distributed generation. We quantify the sustainability and reliability of MGs in a regional power market in terms of multiple indices for the regional grid. The setting is the Northwestern European electricity market (Belgium, France, Germany and the Netherlands). This is a regional network whose national markets already influence each other strongly and have taken steps to integrate even further into a single market. Since 2006, for example, the Netherlands, France and Belgium have coupled their electricity exchanges through the Trilateral Market Coupling (TLC), ensuring the convergence of spot electricity prices in the three countries. In November 2010, the TLC was replaced by the Central Western European Market Coupling (CWE), which also includes Germany [1] [2].

Sustainable development is often defined as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs" [3]. Translating this definition into quantifiable criteria that can be used to compare alternative power systems has proven difficult. For this reason, several authors have adopted a multi-criteria (or multiple objective) approach. The function of multi-criteria analysis is to communicate tradeoffs among conflicting criteria and to help users quantify and apply value judgments in order to recommend a course of action [4]. In this manner, a range of dimensions of sustainability can be considered, while allowing stakeholder groups to have different priorities among the criteria. This method has been used, for example, to assess the tradeoffs in power system planning [5] and to evaluate the sustainability of power generation [6].

The main contribution of this paper is the quantification of the sustainability and reliability of alternative power generation paths in a regional system with a diverse set of metrics. We explicitly simulate the impacts of a generation investment decision on operations and investment elsewhere in the grid, as evaluation of the net sustainability impacts of a decision should consider how a given investment choice propagates through the system. Our approach does not rely on multi-objective optimization; it presents instead a multi-criteria assessment through the use of indicators, which are calculated based on the results of a single-objective optimization model and a reliability model.

Among the commonly used four dimensions to evaluate the sustainability of energy supply systems (social, economic, technical and environmental) [7], the analysis emphasizes the latter three. In terms of microgrid impact on social sustainability, several areas commonly cited as important are equity, community impacts, level of participation in decision making and health impacts. The first three depend on how a given microgrid is owned and managed. In general, it is plausible that the increased impact that members of the microgrid-served pop-

*Corresponding author at Johns Hopkins University, Department of Geography and Environmental Engineering, 3400 North Charles Street, 313 Ames Hall. Baltimore, MD, 21218, USA. Email address: chiara.lo.prete@jhu.edu. Phone number: 410-516-5137. Fax number: 410-516-8996.

ulation could have on ownership and management decisions, relative to populations served by conventional utilities, would count as a positive impact on social sustainability. Additionally, shared community values may lead some stakeholders to value microgrids that use renewable energy more highly than either microgrids that do not or larger systems in which the community has little choice about the source of electricity [8]. Increased security of supply associated with microgrids may also offer social as well as economic benefits within and outside the community served by a microgrid. Finally, microgrid operation may create jobs that offer social sustainability gains for the local community.

On the other hand, microgrids may have negative effects on residents' quality of life, if they increase the level of noise or have aesthetic impacts on the landscape [9]. Health impacts of a microgrid may also be negative, as microgrids are likely to have generation and thus pollution closer to the populations they serve than conventional distribution networks. How risks to life and health associated with local air pollution compare with the ones from a conventional utility source will be very population, site and technology specific.

While we can speculate on the likely direction of these impacts for the power system modeled in this paper, it is difficult to quantify them without reference to a specific location and population whose views and willingness to pay can be surveyed or estimated. On the contrary, the methodology used in our analysis aims at assessing the broader impacts of alternative power generation paths on a regional power system. For this reason, no direct quantification of social sustainability is offered in our study. However, to account indirectly for this dimension we perform a sensitivity analysis on the results in order to assess whether and how the introduction of a social sustainability index would alter our conclusions.

We consider six alternative scenarios for satisfying the electric power and thermal needs of a regional power market, and we characterize their sustainability and reliability using four sets of indicators. The scenarios are various combinations of microgrid implementation (with and without MGs), microgrid generating mix (fossil-fueled only, or fossil-fueled and renewable) and CO_2 policies (with and without a price on CO_2 emission allowances). The first set of indices is based on CO_2 and conventional air pollutant emissions (NO_x and SO_x). The second one emphasizes economic sustainability in terms of total generation costs [10] and accounts for externalities of electricity generation. Externalities can be defined as "the costs and benefits which arise when the social or economic activities of one group of people have an impact on another, and when the first group fails to fully account for their impacts" [11]. In the 1990s the importance of environmental costs as an input to the planning and decision processes of electric power generation systems was recognized in several studies [12] [13]. The third set of indices is based on thermodynamic energy and exergy based efficiencies, while the fourth considers effects on bulk power system reliability.

Economic and environmental analyses of power systems including distributed generation are common (see, for example, [14] and [15]). Several studies assess the potential benefits of distributed generation [16] [17] and evaluate its impact on sustainable development [18]. Others focus directly on the economic and regulatory issues of MG implementation [19], on the implications of environmental regulation on MG adoption [20], and on the improvement in power reliability provided to different types of buildings by the installation of a MG [21]. In contrast, neither thermodynamic analyses considering the interaction of MGs with existing regional power systems nor the effect of MG deployment on system reliability have been previously published, to the best of our knowledge.

We include exergy because an analysis relying on first law efficiency alone does not consider to what degree the outputs of a power plant are useful. For example, electricity is more valuable than steam, one of the typical by-products of power production, because the latter is characterized on a per unit energy basis by a lower value of exergy than electricity. Therefore, not all outputs should be valued in the same way: outputs having a higher quality or exergy per unit energy (like electricity) should have a higher unit price than those having a lower quality or exergy per unit energy (like steam) because the former possess a greater ability to do work. In contrast, when the second law of thermodynamics is disregarded, the difference in quality of the various energy outputs is not considered and cannot be effectively compared for different energy conversion processes.

Thus, the use of exergy-based indicators can help decision makers to improve the effectiveness of energy resource use in a given system. Such indicators have been widely adopted in the sustainability literature. Yi et al. [22] use thermodynamic indices to assess the sustainability of industrial processes. Frangopoulos and Keramioti [23] evaluate the performance of different alternatives to meet the energy needs of an industrial unit, taking into account several aspects of sustainability. von Spakovsky and Frangopoulos [24] [25] use an environomic (thermodynamic, environmental and economic) objective for the analysis and optimization of a gas turbine cycle with cogeneration. Rosen [26] presents a thermodynamic comparison of a coal and a nuclear power plant on the basis of exergy and energy. Zvolinschi et al. [27] develop three exergy-based indices to assess the sustainability of power generation in Norway.

In addition to sustainability, it is important to incorporate a reliability analysis in the decision process because of the positive impact that microgrids may have on power system reliability, and thereby on promoting their deployment. Therefore, we add reliability to our suite of indices and quantify it using the annual Loss of Load Probability (LOLP) and Expected Loss of Energy (ELOE) [28] [29]. The reliability of a power system is the probability that the system is able to perform its intended function (generation meets load), under a contractual quality of service, for a specified period of time. Reliability is quantified here using the concept of "long-run average availability" of the bulk power system (supply-demand balance), without consideration of dynamic system response to disturbances, which instead is the concept of "security" [30].

We do not consider aspects of power quality that may also be controlled within MGs. It has been argued that microgrids have the potential to deliver different degrees of power quality tailored for different customers' needs, as they may be employed to control power quality locally according to customers' requirements. This may prove to be more beneficial than providing a uniform level of quality and service to all customers without differentiating among their needs [31] [32]. However, the way in which microgrids may affect power quality in a regional grid is still under study and there are no definitive results. For this reason, we do not include power quality considerations in our analysis, though we note they should be addressed in future research.

We also do not consider customer outages arising at the sub-transmission or distribution-level. However, it is worth noting that the majority of power interruptions experienced by customers in the countries we consider are not due to large events at the bulk level, but to more localized ones affecting the distribution system [33].

Section 2 describes our modeling approach, data and assumptions concerning alternative power systems (with and without MGs) and CO_2 policies. Section 3 presents the six scenarios considered in our analysis to satisfy the electric power and thermal needs of the Northwestern European electricity market. Section 4 describes the indicators chosen in this paper to assess the sustainability and reliability of the network. Section 5 discusses the results of the analysis, while Section 6 concludes.

2. Methodology and data

Two different models are used to quantify our indices. A regional power market model based on linear optimization methods [10] [34] provides the information necessary for the economic, environmental and thermodynamic indices; the model is presented in Section 2.1. A local reliability model based on convolution methods [28] [29], described in Section 2.2, is used instead to obtain the reliability indices.

2.1. Regional market simulation model

For the purposes of this paper, we represent the Northwestern European electricity market using COMPETES (Comprehensive Market Power in Electricity Transmission and Energy Simulator) [35]. Our version of COMPETES is a quadratically constrained model solved in ILOG OPL 6.3, using the optimizer Cplex12. COMPETES models twelve power producers in the four countries: eight of them are the largest ones in the region (Electrabel, Edf, Eon, ENBW, RWE, Vattenfall, Essent Nuon-Reliant), while the remaining four represent the competitive fringe in each country.

When no MGs are included, the electricity network is represented by fifteen nodes. Each of the seven main nodes (Krim, Maas and Zwol in the Netherlands; Merc and Gram in Belgium; one node in France and one in Germany) has generation capacity and load. A DC power flow model is used to represent a system in which four intermediate nodes are distinguished in both France (Avel, Lonn, Moul, Muhl) and Germany (Diel, Romm, Ucht, Eich); at these nodes, no generation or demand occurs (except for 2,000 MW of power exports to the UK at Avel). Three nodes representing groups of residential MGs are added to the model in the MG scenarios.

The nodes of the network are connected by twenty-eight high voltage transmission corridors (or arcs), each one with a maximum MW transmission capacity. The groups of MGs are connected to the transmission system by radial links at nodes Krim, Maas and Zwol in the Netherlands. While by assumption we are focusing on the impact of new microgrids in the Netherlands, to understand their impacts on the regional power grid it is necessary to consider the neighboring countries' bulk power markets. Of course, groups of microgrids could also be connected to nodes in other countries. However, we would then need to consider additional neighboring countries, such as Poland or the Iberian peninsula.

Computational convenience suggests starting the analysis with a competitive benchmark. Our application of COMPETES calculates a competitive equilibrium among power producers, which under the assumption of perfectly inelastic demand is equivalent to minimization of total generation costs. This is done for six representative hours in order to characterize the distribution of operating costs.

We include resistance losses on high voltage transmission flows to make the model more realistic because, on average, losses can contribute as much to spatial price variations as congestion does. Losses vary as a quadratic function of flow, using the DC formulation with quadratic losses in [36]. In the absence of other data, resistance loss coefficients, defined for the twenty-eight corridors of the network, are assumed to be proportional to reactance. Therefore, we set them equal to the reactance on each corridor times a constant α, whose value is chosen so that high voltage transmission losses are approximately equal to 2% of generation during the peak hours.

2.1.1. Model formulation

COMPETES is a short-run market simulation model using an optimization formulation: its objective function includes short-run marginal costs (i.e., fuel and other variable O&M costs) and disregards long-run retirement and entry decisions. For each MG and CO_2 policy scenario, we solve the model for six different periods of the year representing a variety of load and generation capacity conditions. The six periods are appropriately weighted by the number of hours in each period to estimate annual cost. The problem statement is as follows:

$$\min \sum_{i} \sum_{j \in J_i} (MC_{ij} + CO_2 E_{ij}) gen_{ij} \tag{1}$$

subject to:

$$\sum_{j \in J_i} gen_{ij} + \sum_{k \in A_i} [f_{ki}(1 - Loss_{ki} f_{ki}) - f_{ik}] \geq L_i \quad \forall i \in I \tag{2}$$

$$\sum_{ik \in M_m} R_{ik} S_{ikm} (f_{ik} - f_{ki}) = 0 \quad \forall m \in M \tag{3}$$

$$gen_{ij} \leq Cap_{ij} \quad \forall i \in I, \forall j \in J_i \tag{4}$$

$$f_{ik} \leq T_{ik} \quad \forall i, k \in I \tag{5}$$

$$f_{ik} \geq 0 \quad \forall i, k \in I \tag{6}$$

$$gen_{ij} \geq 0 \quad \forall i \in I, \forall j \in J_i \tag{7}$$

A complete list of variable and parameter definitions is provided in the nomenclature. The goal is to minimize the objective function expressed as the total generation costs given by equation 1, where a linear short-run cost of production is assumed. The decision variables are gen_{ij} (the generation from aggregated power plant j located at node i) and f_{ik} (the MW transmission flow from node i to a nearby node k that is directly connected to i by a transmission corridor).

Equation 2 accounts for Kirchhoff's Current Law (KCL), applied to each node of the network. f_{ik} is the export flow from node i to node k, while $f_{ki}(1\text{-}Loss_{ki} f_{ki})$ represents the import flow (net of losses) into node i from node k. Equation 3 represents Kirchhoff's Voltage Law (KVL) constraint, defined for each of the fourteen meshes (or loops) connecting the nodes. Equation 4 ensures that power generated at each node and each step is less than the available capacity at that location, while equation 5 constrains the transmission flow on a given arc. Equations 6 and 7 are nonnegativity restrictions.

When microgrids are included, their generation costs are added to equation 1. Since the groups of MGs are additional nodes with autonomous loads, one KCL constraint is added in the model for each MG node. However, no additional KVL is included because MGs are assumed to be radially connected to the grid. The power generated at each MG node must satisfy the capacity constraint (equation 4) and the non-negativity constraint (equation 7), and its flow to/from the grid must satisfy bounds 5 and 6.

2.1.2. Data

Simulations of power market outcomes are based on a modified version of the Energy Research Centre of the Netherlands (ECN) COMPETES database of transmission, demand and generation [37].

This provides a multi-step supply function (one step per aggregate power plant) for each node where power generation occurs. Using the information in [38] and [39], generation costs and capacity of the original fifteen nodes of the network in [37] have been updated to 2008 (a leap year). Our version of the database has also been modified to account for transmission resistance losses, exergetic and energetic efficiencies, and emissions.

In the scenarios including MGs, nine steps representing MG technologies (three for each node to which MGs are connected) have been added to the existing network. Generation costs, technology types and capacity for the MG nodes are obtained from the literature.

In line with [37], in the scenarios without MGs the capacity database does not include renewable and combined heat and power (CHP) generators. On the other hand, CHP capacity is installed at the MG nodes and we explicitly consider its contribution to the system.

Hourly loads in the four countries are based on [40] and refer to 2008. Since CHP and renewable generators are not included in the capacity database, their production is netted from the hourly electricity demand of the network in [40]. Hourly loads are organized in load duration curves (LDCs) and divided into six blocks: the first block averages the load of the first 100 hours, the second block of the following 900 hours, the third and fourth of the next 2,500 hours, the fifth of the next 2,284 hours, the sixth of the last 500 hours. The average electricity consumption of the residential customers in the MGs is based on the load profiles in [41]. Information on total capacity, dominant fuel type, energy efficiency, exergy calculations, marginal cost function and average CO_2, NO_x, SO_x emission rates for all the nodes in the network is available from the authors.

2.2. Reliability valuation model

In addition to the market simulation model, we develop a model to assess the reliability of the Dutch power system in two scenarios (with and without MGs). We consider the Dutch system alone for two reasons. First, we focus our analysis on the direct impact of MGs on the reliability in the country where they are installed. Second, the Netherlands is the most import-dependent of the four countries considered, and the adequacy of generating capacity to meet future energy needs has been extensively debated over the last decade [42]. We include two reliability indices, the LOLP and the ELOE. The LOLP of a power system is the expected number of hours of capacity deficiency in the system in a given period of time [29]. In our analysis, the LOLP is expressed in outage hours/10 years: an outage of 8 hours in 10 years is typically considered a reasonable reliability target in industrialized countries. The ELOE gives an indication of the amount of load that cannot be serviced in a given period of time and is expressed in MWh/yr [28].

In our model, 2008 summer and winter LDCs are approximated using the mixture of normals approximation (MONA) technique detailed in [43]. Given z = 1,..,Z independent normal random variables, each with mean μ_z, variance σ_z^2, and cumulative distribution function $\Phi(\cdot;\, \mu_z,\, \sigma_z^2)$, $F(\cdot)$ has a mixture of normals distribution with z components if

$$F(x) = \sum_z p_z \Phi(x; \mu_z, \sigma_z^2) \tag{8}$$

$$\sum_z p_z = 1; \quad 0 \leq p_z \leq 1 \tag{9}$$

where p_z is the weight of the z^{th} component. A LDC can be approximated by

$$LDC(x) = 1 - F(x) \tag{10}$$

For our purposes, a two-component mixture of normals provides an excellent approximation of the load duration curve; the weights, mean and variances in equation 8, different for winter and summer loads, are obtained by minimizing the squared difference between the original and approximated distributions, with higher penalties on deviations during peak periods. In the reliability analysis, loads include CHP and renewable production.

We define the expected available capacity and the variance of available capacity of supply function step j at node i as:

$$E(Cap_{ij}) = [Cap_{ij}(1 - FOR_{ij})] \tag{11}$$

$$Var(Cap_{ij}) = \frac{1}{N_{ij}}[(Cap_{ij})^2 FOR_{ij}(1 - FOR_{ij})] \quad (12)$$

where N_{ij} is the number of individual power plants at aggregate step j and FOR_{ij} is the forced outage rate of each individual power plant in step j. These expressions are based on a binomial distribution approximation, assuming N_{ij} independent generators in the step. The forced outage rates of the central generators are obtained for each technology type from [44]. In the absence of other specific data, we use [45] for the MG technologies. We assume that summer and winter available generating capacity follows a normal distribution, with mean equal to the total expected generating capacity and variance equal to the sum of variances at all steps of the supply function.

In the reliability analysis, power generation capacity includes an estimate of the CHP capacity in the Netherlands. It also accounts for the maximum feasible flow of power imports to the Netherlands from neighboring countries, assuming that under highly stressed conditions the Dutch system will maximize imports. The maximum flow is based on the COMPETES simulations under peak demand conditions.

Since wind power accounted for about 5% of 2008 electricity net production in the Netherlands [39], its production should be netted from electricity demand in our reliability analysis. The time series of wind generation over 15-minute intervals in one representative year [46] suggests that the density function of wind power generation in the Netherlands may be adequately approximated by an exponential distribution. This is confirmed by the non rejection of the Kolmogorov-Smirnov test of the exponential distribution of this sample at a 1% significance level. We use two different exponential approximations, one for the winter and one for the summer, with parameter λ_w equal to the average wind production in the Netherlands in the two seasons (556.5 MW in the summer and 378 MW in the winter, based on [46]).

In season w, the LOLP of each component of the normal mixture approximation z ($LOLP_{w,z}$) is defined as

$$\begin{aligned} LOLP_{w,z} &= Prob(L_z - Cap_w - Wind_w \geq 0) \\ &= \int_0^\infty f_{L_z - Cap_w}(x) F_{Wind_W}(x)dx \end{aligned} \quad (13)$$

where x represents the value of the thermal generation capacity deficit $(L_z - Cap_w)$, $f_{L_z-Cap_w}(x)$ is the normal density function of $(L_z - Cap_w)$ evaluated at x, and F_{Wind_W}(x) is the exponential cumulative distribution function of $Wind_w$ evaluated at x. We can express the $LOLP_{w,z}$ as a product of functions because, according to [46], wind generation is largely independent of load in that area of Europe. The four values of $LOLP_{w,z}$ (one for each season and each of the two components of our normal mixture approximation) are appropriately weighted by the probabilities p_z and the number of hours in each season to estimate the annual LOLP.

In season w, the ELOE of each component of the normal mixture approximation z ($ELOE_{w,z}$) is defined as:

$$\begin{aligned} ELOE_{w,z} &= \int_0^\infty \int_0^x f_{L_z-Cap_w}(x) f_{Wind_W}(y)(x-y)dydx \\ &= \int_0^\infty f_{L_z-Cap_w}(x)[x + \tfrac{1}{\lambda_w}(e^{-\lambda_w x} - 1)]dx \end{aligned} \quad (14)$$

Table 1: Characteristics of the network

Annual electric power load (TWh/yr)	1,104
Thermal load (MWht/yr)	5,909,115
Exergy content of the thermal load (MWh/yr)	2,282,768
Boiler capacity displaced by the MGs in Scenarios 2 and 5 (MW)	1,132
Boiler capacity displaced by the MGs in Scenarios 3 and 6 (MW)	895
Efficiency of the boilers	0.90
Peak power generating capacity (MW)	233,511

Similarly to the $LOLP_{w,z}$, each $ELOE_{w,z}$ is appropriately weighted by the probabilities p_z and the number of hours in each season to estimate the annual ELOE.

3. Description of the scenarios

We consider six alternative scenarios to satisfy the electric power and thermal needs of the Northwestern European electricity market. In every scenario we simulate six representative hours, one for each block defined in section 2.1.2. Annual results are obtained by averaging the hourly results by the number of hours in each block. The scenarios can be described as follows.

- *Scenario 1: no MG, no CO_2 price.* This scenario assumes that no MG operates in the Northwestern European power market and there is no price on CO_2 emissions. The characteristics of the network are summarized in Table 1. The only thermal load we consider is the one of the customers that could potentially be served by MGs; this is a thermal load of 5.9 TWht/yr, met by natural gas fueled boilers in this scenario and supplied to the residential district as saturated steam at p = 20 bar.

- *Scenario 2: MG, fossil-fueled generation technologies, no CO_2 price.* This scenario assumes that fifty residential fossil-fueled MGs operate in the Netherlands, connected to nodes Krim (16 MGs), Maas (17 MGs) and Zwol (17 MGs), and there is no price on CO_2 emissions. Each residential MG has a 24 MW generating capacity and serves about 30,000 customers. The generating mix at every MG node includes Solid Oxide Fuel Cells (SOFCs), natural gas microturbines (MTs) and diesel reciprocating engines (REs). The total capacity installed in the three MGs represents about 8% of the generating capacity in the Netherlands, and about 0.5% of the generating capacity of the entire regional grid. The assumed characteristics of the three MG nodes are summarized in Table 2. The annual electric power and thermal load of the network at the consumer voltage level are the same as in Scenario 1, in line with our zero elasticity assumption. However, the load at the bulk power level will be lower because MGs generate power closer to the consumers, lowering the transmission losses of the network. The thermal load (5.9 TWht/yr) is entirely satisfied by the CHP generating technologies installed at the MG level.

Table 2: Characteristics of the MG nodes

Annual electric power load (MWh/yr)	4,643,223
Thermal load (MWht/yr)	5,909,115
Exergy content of this thermal load (MWh/yr)	2,282,768
Thermal load satisfied by the MGs in Scenarios 3 and 6 (MWht/yr)	3,948,252
Thermal load satisfied by boilers in Scenarios 3 and 6 (MWht/yr)	1,960,863
Peak power generating capacity (MW)	1,330
of which:	
SOFCs or PV system/battery	*20%*
Natural gas MTs	*40%*
Diesel REs	*40%*

When MGs are present, the hourly load of the system at the bulk level is reduced by 1,212 MW in the peak period (first load block). This amount is equal to the maximum hourly load of the three MG nodes at the consumer voltage level (1,036 MW, occurring during winter peak hours), plus 2% of avoided transmission losses on that load and a 15% reserve margin. We assume that 1,057 MW less of central system natural gas-fired combined cycle (CC) plant would be built if MGs operate in the system, so this amount is subtracted from this type of generating capacity operating at the three Dutch nodes in the MG scenarios. We subtract only CC-type generators because we assume this type of capacity is the most recent central station thermal capacity constructed in the system. In addition, a peaking (combustion turbine - CT) capacity equal to 15% of that amount (155 MW) is assumed to no longer be needed as a reserve margin.

- *Scenario 3: MG, fossil-fueled and photovoltaic generation technologies, no CO_2 price.* This scenario is similar to the previous one. However, the power generation mix at each MG node is different and includes solar photovoltaic (PV), natural gas microturbines (MTs) and diesel reciprocating engines (REs) (Table 2). PV does not generate pollutant emissions during operation and does not contribute to heat generation; as a result, the thermal load of the MG customers (5.9 TWht/yr) is satisfied partially by CHP and partially by natural gas fueled boilers. Assessing the reliability of a system including renewable generators goes beyond the scope of our analysis; for this reason, we assume the same reliability of Scenario 2, although this might represent an optimistic estimate. Table 3 details the share of generating capacity by fuel in the regional grid.

- *Scenario 4: no MG, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 1 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.

- *Scenario 5: MG, fossil-fueled generation technologies, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 2 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.

- *Scenario 6: MG, fossil-fueled and photovoltaic generation technologies, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 3 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.

Table 3: Generating capacity in the network by fuel

	Scenario 1 and 4 No MGs		Scenario 2 and 5 MGs Fossil fuels only		Scenario 3 and 6 MGs Fossil fuels + PV	
Fuel	MW	share	MW	share	MW	share
Nuclear	101,583.5	43.5%	101,583.5	43.5%	101,583.5	43.3%
Coal	72,437.7	31.0%	72,437.7	31.0%	72,437.7	30.8%
Natural gas	38,073.0	16.3%	37,671.0	16.1%	37,432.7	15.9%
Oil	15,549.9	6.7%	16,069.5	6.9%	16,069.5	6.8%
Hydro	4,722.2	2.0%	4,722.2	2.0%	4,722.2	2.0%
Waste	1,144.3	0.5%	1,144.3	0.5%	1,144.3	0.5%
PV	-	-	-	-	1,638.4	0.7%
Total	233,510.6		233,628.1		235,028.2	

4. Indicators

We chose our indicators based on [23] to assess different aspects of economic, technical and environmental sustainability. We also include two indicators commonly used in the literature to measure power system adequacy [28]. The indicators are classified into four groups.

4.1. Environmental Indicators

The three environmental indicators are:

1. *Annual emissions of CO_2* (Mton/yr)
2. *Annual emissions of NO_x*(kton/yr)
3. *Annual emissions of SO_x*(kton/yr)

We consider the pollutant emissions produced by the power plants operating in the network, as well as by the natural gas fueled boilers, when these operate to satisfy part or all of the heat load of the network. We also include an estimate of the complete fuel chain emissions for nuclear, coal and natural gas power plants, representing the bulk of generating technologies in the regional network (Table 3). For nuclear power plants, we include typical CO_2, NO_x and SO_x emissions calculated on a lifecycle basis in [47]. We increase the emissions from coal and natural gas generators to account for the ones occurring in the fuel production, transport, and disposal portions of the fuel cycle. This is done using the values detailed in [48] and [49]. It is important to emphasize that our goal is not to perform a detailed life-cycle analysis of all power plants operating in the regional grid, which would require the use of information that is not readily available, but to provide an estimate of the life-cycle emissions of the bulk of generating capacity.

Scenarios 1, 3, 4 and 6 include emissions from power generation and boilers (in addition to estimated life-cycle emissions for nuclear, coal and natural gas power plants). On the contrary, in Scenarios 2 and 5 the only pollutant emissions considered are due to the power plants operating in the network. There are no emissions from boilers in this case, as the heat requirement of the microgrids is entirely provided by their CHP technologies. The emission rates of the boilers are 0.606 ton CO_2/MWht and 0.00061 ton NO_x/MWht [50]. The emission rates for the regional grid and MG nodes are provided in Tables 4 and 5. It is worth emphasizing that the emission rates shown in Table 4 do not refer to modern plants only, but are averages of different types of existing plants in the power generating park of the four countries. The existing capacity is dominated by less efficient steam plants.

Table 4: Average emission rates in the network by fuel

Fuel	CO_2	NO_x	SO_x
Natural gas	0.57	0.0004	1.94e-06
Coal	0.99	0.0016	0.0021
Waste	0.63	0.0015	0.0020
Oil	0.73	0.0018	0.0016

Note: emission rates are in ton/MWh power generated. Values are averages of existing generating technologies in the network. Source: ECN.

Table 5: Emission rates in the MGs by technology

Technology	CO_2	NO_x	SO_x	Source
SOFCs	0.513	-	-	[51]
Gas MTs	0.700	0.000068	0.000003	[52]
Diesel REs	0.651	0.00991	0.000206	[53]

Note: emission rates are in ton/MWh power generated.

4.2. *Economic Indicators*

The two economic indicators are:

4. *Annualized capital costs and variable costs* (€/yr). In Scenarios 1 and 4, the capital cost impact is given by the annualized costs of the natural gas combined cycle and combustion turbine generation that would not be necessary in the MG scenario, plus the cost of the boiler capacity. We only consider the cost of units potentially replaced by MGs, as the one of other units represents a fixed cost in all scenarios and therefore can be disregarded, since it won't affect the differences among the systems, which is what determines the ranking of the scenarios. The annualized capital costs are computed by multiplying the current value of capital by an annualization factor $\frac{r(1+r)^n}{(1+r)^n-1}$, where r is the discount rate and n is the useful life of the item. The assumptions used are given in Table 6.

   The economic impact also includes the variable costs of operation of each scenario. The costs of the CO_2 allowances are not included in the economic indices because they simply represent a money transfer from the power generators to the government.

   In Scenarios 2 and 5, we consider the annualized capital costs and operating variable costs of the new MG capacity.

Table 6: Economic data for Scenarios 1 and 4

Capital cost of CC capacity ($/kW)	1,200
Capital cost of CT capacity ($/kW)	1,000
Total unbuilt CC capacity (MW)	1,057
Total unbuilt CT capacity (MW)	155
Useful life of gas capacity (years)	20
Capital cost of boilers ($/kW)	240
Useful life of boilers (years)	20
Cost of natural gas (€/MBtu)	6.4
Discount rate	0.05
Exchange rate (€/US$)	0.724

In addition to these, Scenarios 3 and 6 include the costs for the boiler capacity needed to satisfy part of the heat load of the network. The characteristics of the MG technologies are given in Table 7.

Table 7: Characteristics of the MG technologies

Technology	Capital cost	Useful life (years)	Energetic efficiency
PV system	5,884 $/kW	20	81%
Lead-acid battery	435 $/kWh	10	90%
SOFCs	4,700 $/kW	10	50%
Gas MTs	2,500 $/kW	20	26%
Diesel REs	350 $/kW	20	34%

Note: the PV system includes PV array, inverter and charge controller.

5. *Annualized capital costs and variable costs, including environmental externalities* (€/yr). We include an additional term, the external environmental costs of the pollutants, among the variable operating costs of each scenario. We considered using an integrated assessment model like EcoSense Web [54] to evaluate the external costs of NO_x and SO_x. EcoSense allows estimation of external costs of energy technologies by taking account of specific, context dependent variables (e.g., geography, population density). In the context of our analysis, however, we do not make reference to specific sites of each of the many power plants whose output changes in at least one period in the market solutions. Furthermore, we do not have information on the technical parameters of all power plants modeled in our regional system (e.g., stack gas exit velocities), which would be needed as inputs to the EcoSense software. In the ECN database groups of power plants are aggregated into steps of supply functions at each node of the network, and only general characteristics of each step (e.g., aggregate capacity, average efficiency) are available. Therefore, it is not possible to calculate the external costs of NO_x and SO_x using EcoSense Web due to lack of technical data.

   In the absence of other information, we use the NO_x and SO_x country-specific values provided by the NEEDS project [55] to reflect the impacts of power generation. The tools developed in the framework of the NEEDS project do not calculate the damage and external cost due to CO_2, as this is not considered a pollutant but a greenhouse gas. Thus, for the external cost of CO_2 we instead use the value in [23]. External costs are calculated on all emissions, including the indirect ones related to the life-cycle of nuclear, coal and natural gas power plants. The addition of environmental costs allows us to assess the real cost of the pollutant emissions to the society, which cannot be done simply by introducing CO_2 allowances. On the other hand, counting both the external costs of pollution in the cost indices and emissions as separate pollution indices could be viewed as double counting. To account for this, we have performed a sensitivity analysis in Section 5.

4.3. Technical Indicators

The four technical indicators are

6. *Annual energetic electric efficiency of the network.* This indicator is obtained by dividing the annual power production by the annual fuel use for power production in each scenario.

7. *Annual energetic total efficiency of the network*

$$\eta_{tot} = \frac{\dot{W} + \dot{Q}}{\frac{\dot{W}}{\eta_e} + \frac{\dot{Q}}{\eta_b}} \tag{15}$$

The heat rate requirement $\dot{Q}$ is the same in all scenarios. However, in Scenarios 1 and 4 the thermal load has to be met with separate boilers. In Scenarios 2 and 5 the MGs produce heat, through cogeneration, to satisfy their load. Therefore, the second term in the denominator of equation 15 is excluded in these scenarios, because all the fuel necessary to produce both heat and power is already included in the first term. In Scenarios 3 and 6, however, PV does not contribute to heat generation, and as a result the heat load of the network is satisfied partially through CHP and partially through boilers. The second term in the denominator of equation 15 accounts only for the fuel use of the additional boilers needed in these scenarios.

8. *Annual exergetic electric efficiency of the network*

$$\zeta_e = \frac{\eta_e}{\varphi_e} \tag{16}$$

φ_e is the ratio of the total exergy of the annual fuel use for power production and its total energy.

9. *Annual exergetic total efficiency of the network*

$$\zeta_{tot} = \frac{\dot{W} + \dot{E}_S^Q}{\frac{\dot{W}}{\zeta_e} + \dot{E}_{NG}} \tag{17}$$

$$\dot{E}_{NG} = \dot{M}_{NG} \times H_{NG} \times \varphi_{NG} \tag{18}$$

For the reasons explained for indicator 7, the last term in the denominator is excluded in Scenarios 2 and 5, and included with reference to the additional boilers used to satisfy the heat load in Scenarios 3 and 6. $\varphi_{NG} = 1.042$ and $H_{NG} = 38.1$ MJ/kg. The indicators in section 4.3 are described in [56].

Table 8: Values of the indicators, No CO_2 scenarios

Indicator	Scenario 1 No MG	Scenario 2 MG Fossil fuel mix	Scenario 3 MG Fossil + PV mix
Ind.1 CO_2 (Mton/yr)	331.96	328.98	328.97
Ind.2 NO_x (kton/yr)	347.76	343.15	343.05
Ind.3 SO_x (kton/yr)	289.44	281.55	280.67
Ind.4 Cost (M€/yr)	15,291	15,180	15,808
Ind.5 Cost+Extern. (M€/yr)	25,832	25,648	26,268
Ind.6 Eff.En.El.	0.4584	0.4583	0.4585
Ind.7 Eff.En.Tot.	0.4595	0.4607	0.4606
Ind.8 Eff.Ex.El.	0.4134	0.4133	0.4135
Ind.9 Eff.Ex.Tot.	0.4580	0.4592	0.4590
Ind.10 LOLP (hours/decade)	7.70	5.53	5.53
Ind.11 ELOE (MWh/yr)	220.35	152.82	152.82

4.4. Reliability Indicators

The two reliability indicators are

10. *Annual LOLP* (outage hours/10 years)

11. *Annual ELOE* (MWh/year)

5. Results

The indicators are calculated based on the results of the optimization problem and the reliability valuation model described above. Indicator values for each scenario are shown in Table 8 and 9. To analyze the trend of the emissions from power generation alone, we disregard the CO_2 and NO_x emissions of the boilers, as well as the estimated life-cycle emissions of nuclear, coal and natural gas plants (Table 10).

5.1. Base case

In the scenarios without MGs, total emissions are higher than in the ones including MGs. This is because in the non-MG scenarios boilers are used to satisfy the entire load of the network, and thus contribute to the production of pollutant emissions. However, Table 10 shows that SO_x emissions from power generation are higher in the scenarios including MGs. This happens because in the MG scenarios some high SO_x power plants fueled by coal and oil increase their output to meet the load of the network, replacing the production of the unbuilt CC and CT

Table 9: Values of the indicators, CO_2=25 €/ton scenarios

Indicator	Scenario 4 No MG	Scenario 5 MG Fossil fuel mix	Scenario 6 MG Fossil + PV mix
Ind.1 CO_2 (Mton/yr)	318.26	314.60	314.51
Ind.2 NO_x (kton/yr)	339.45	334.70	334.52
Ind.3 SO_x (kton/yr)	280.01	271.17	270.24
Ind.4 Cost (M€/yr)	15,446	15,339	15,984
Ind.5 Cost+Extern. (M€/yr)	25,583	25,383	26,018
Ind.6 Eff.En.El.	0.4607	0.4608	0.4611
Ind.7 Eff.En.Tot.	0.4618	0.4633	0.4631
Ind.8 Eff.Ex.El.	0.4155	0.4155	0.4158
Ind.9 Eff.Ex.Tot.	0.4603	0.4617	0.4616
Ind.10 LOLP (hours/decade)	7.70	5.53	5.53
Ind.11 ELOE (MWh/yr)	220.35	152.82	152.82

Table 10: Emissions from power generation

Pollutant	Scen.1	Scen.2	Scen.3	Scen.4	Scen.5	Scen.6
CO_2 (Mton/yr)	313.70	314.28	313.26	299.84	299.78	298.70
NO_x (kton/yr)	248.53	247.36	247.36	240.16	239.13	239.13
SO_x (kton/yr)	212.89	213.67	213.67	203.44	203.66	203.66

power plants. For the same reason, CO_2 emissions from power generation are also higher, when no price on allowances exists.

If environmental externalities of electricity production are not considered, the costs of the scenarios with and without fossil-fueled MGs are comparable; the difference, about 100 million euros, is due to the fact that more efficient technologies decrease the annual fuel consumption in the network when MGs are present. The costs of the scenarios including PV are instead about 500 million euros higher than the ones without MGs, and about 600 million euros higher than the ones including only fossil-fueled microgrids; the difference is due to much higher capital costs for the installation of PV systems and lead-acid battery banks. When externalities are considered, the gap between the costs of scenarios 1 and 4 (and 2 and 5) widens to approximately 200 million euros: in the non-MG scenarios costs are higher because they also include the external costs of heat production from the boilers. Comparing MG scenarios, while the ones including only fossil-fueled technologies have lower environmental costs, those including PV also account for the costs of the boilers needed to satisfy part of the heat load of the network; total environmental costs are therefore of similar magnitude.

The efficiencies of the MG scenarios (in particular total efficiencies) are higher than those of the other scenarios because of the increased amount of cogeneration. The introduction of even a moderate amount of MG capacity (8% of the generating capacity in the Netherlands) leads to an improvement by about 30% in the overall reliability of the Dutch system, as measured by the LOLP and ELOE. As mentioned previously, the estimate of reliability provided by the PV/fossil-fuel system may be optimistic.

It is difficult to assess the overall performance of the scenarios if each indicator is expressed in different units; this is the central challenge posed by multi-criteria decision problems. In line with [23], we normalize the values in Tables 8 and 9 after specifying a lower and upper threshold for each indicator. For the first five indicators the lower threshold is set equal to the lowest value among scenarios of the indicator, while the upper threshold is set equal to the highest value of the indicator. For the other indicators, a lower threshold of zero is chosen. Following [23], the upper threshold of η_e is set equal to 80% (the efficiency of a Carnot cycle operating between the environmental temperature of 298.15°K and an assumed temperature of 1486.7°K at the exit of the combustion chamber of the cogeneration system in the MG). Other efficiencies have an upper threshold of 1. For the LOLP the upper threshold corresponds to an outage of 24 hours/decade, while for the ELOE it is an expected loss of load of 1,000 MWh/yr. The values of the normalized indicators are shown in Table 11.

We calculate a sub-index for each group, obtained as the average of the indicators in the group. Each indicator is equally weighted. Finally, we aggregate our results in a composite sustainability index to gauge the overall performance of each scenario. The composite index is a simple average of the four sub-indices. If all sub-indices are given equal weights, a power network including fossil-fueled MGs and a price on CO_2 emission allowances achieves the highest sustainability, with a composite index of 0.792.

5.2. Sensitivity analysis 1: different weights

Our equal weighting may, of course, not be appropriate, depending on societal willingness-to-pay for emission reductions, cost reductions, efficiency improvements and reliability: for this reason we performed some sensitivity analyses. Results are given in Table 12. First, we assign more weight to each dimension (environmental, economic, technical and reliability) in turn. In all cases, Scenario 5 (fossil-fueled MGs and a price on CO_2 emission allowances) continues to represent the best alternative. However, the ranking of the other alternatives is different, depending on which dimension is given more or less weight.

5.3. Sensitivity analysis 2: social sustainability

To assess whether social sustainability considerations could change the outcome of the analysis, we have also performed a sensitivity analysis on the normalized values of the indicators. The goal is to assess how the introduction of a generic

Table 11: Normalized values of the indicators

Indicator	Scenario 1 No CO_2 No MG	Scenario 2 No CO_2 MG Fossil fuel mix	Scenario 3 No CO_2 MG Fossil + PV mix	Scenario 4 CO_2=25 €/ton No MG	Scenario 5 CO_2=25 €/ton MG Fossil fuel mix	Scenario 6 CO_2=25 €/ton MG Fossil + PV mix
Ind.1 CO_2	0.00	0.17	0.17	0.79	0.99	1.00
Ind.2 NO_x	0.00	0.35	0.36	0.63	0.99	1.00
Ind.3 SO_x	0.00	0.41	0.46	0.49	0.95	1.00
Environmental Subindex	**0.00**	**0.31**	**0.33**	**0.63**	**0.98**	**1.00**
Ind.4 Cost	0.86	1.00	0.22	0.67	0.80	0.00
Ind.5 Cost+Extern.	0.49	0.70	0.00	0.78	1.00	0.28
Economic Subindex	**0.68**	**0.85**	**0.11**	**0.72**	**0.90**	**0.14**
Ind.6 Eff.En.El.	0.5730	0.5728	0.5732	0.5759	0.5760	0.5764
Ind.7 Eff.En.Tot.	0.4595	0.4607	0.4606	0.4618	0.4633	0.4631
Ind.8 Eff.Ex.El.	0.4134	0.4133	0.4135	0.4155	0.4155	0.4158
Ind.9 Eff.Ex.Tot.	0.4580	0.4592	0.4590	0.4603	0.4617	0.4616
Technical Subindex	**0.4759**	**0.4765**	**0.4766**	**0.4784**	**0.4791**	**0.4792**
Ind.10 LOLP	0.68	0.77	0.77	0.68	0.77	0.77
Ind.11 ELOE	0.78	0.85	0.85	0.78	0.85	0.85
Reliability Subindex	**0.73**	**0.81**	**0.81**	**0.73**	**0.81**	**0.81**
Composite Subindex	**0.471**	**0.611**	**0.431**	**0.641**	**0.792**	**0.607**

social sustainability subindex might alter the results presented in our analysis. Table 12 shows the value that the social sustainability subindex would need to have, in order to achieve the same composite sustainability of the best alternative (0.792), if all criteria (environmental, economic, technical, social and reliability) were equally weighted. Even a terrible performance of the best scenario on the social sustainability indicator (i.e., a normalized value of its social indicator equal to zero) and an optimal performance of other scenarios (i.e., a normalized value of their social indicator equal to one) would not be enough to dislodge Scenario 5 from its top spot. Therefore, the inclusion of a social sustainability index would not significantly alter the conclusions of this paper.

5.4. Sensitivity analysis 3: exclusion of external costs

To account for the possibility that costs including externalities may duplicate other criteria (in particular, the environmental ones), we have calculated the values of the composite sustainability index disregarding Indicator 5; i.e., we only consider Indicator 4 in the economic sub-index. Table 12 presents the results. Even in this case, Scenario 5 (fossil-fueled MGs and a price on CO_2 emission allowances) achieves the highest composite sustainability index. The gap between the best and second-best alternatives remains similar, compared to the base case scenarios (Section 5.1); however, the ranking of the second and third best alternatives is inverted, with the scenario including MGs and no price on CO_2 performing better than the one without MGs and with a CO_2 price. On the contrary, the ranking of the three worst alternatives remains the same.

6. Conclusions

This paper assesses the sustainability and reliability of microgrids in the Northwestern European electricity market. Results suggest that a power network in which fossil-fueled microgrids and a price on CO_2 emissions are included achieves the highest composite sustainability.

From an environmental point of view, the scenarios including fossil-fueled MGs are more sustainable than the ones where no microgrids are present, because they yield a reduction in total pollutant emissions. However, some direct emissions from power generation may increase. If only a price on CO_2 emis-

Table 12: Values of the composite sustainability index
Sensitivity analyses

Sensitivity analysis	Dimension	Weight	Scenario 1 No CO_2 No MG	Scenario 2 No CO_2 MG Fossil fuel mix	Scenario 3 No CO_2 MG Fossil + PV mix	Scenario 4 CO_2=25 €/ton No MG	Scenario 5 CO_2=25 €/ton MG Fossil fuel mix	Scenario 6 CO_2=25 €/ton MG Fossil + PV mix
1	Environmental Others	70% 10%	0.188	0.431	0.369	0.637	0.903	0.843
1	Economic Other	70% 10%	0.595	0.755	0.238	0.690	0.857	0.328
1	Technical Other	70% 10%	0.474	0.530	0.458	0.544	0.604	0.530
1	Reliability Other	70% 10%	0.626	0.730	0.657	0.694	0.802	0.728
2	Social	20%	2.075	1.513	2.235	1.393	0.00	1.529
3	Indicator 5	0%	0.517	0.649	0.458	0.628	0.767	0.572

sion allowances was included, it would be possible to obtain higher emission reductions at a higher cost; all direct emissions from power generation would decrease. MGs including renewable technologies perform slightly better than the ones having a fossil-fueled generation mix, but the difference is not very significant in our simulations due to the small share assumed for PV.

From an economic point of view, MG scenarios may or may not be more sustainable than the ones excluding MGs, depending on the mix of generation technologies chosen in the microgrids. A large share of expensive technologies, such as fuel cells or photovoltaic, could make these scenarios less desirable than the alternative ones from an economic point of view.

MG scenarios are certainly more thermodynamically efficient because the same electric power and thermal load is satisfied using less energy and exergy. Thus, CHP in the MG produces both heat and power, while in the network electricity is provided by power plants and thermal energy by separate boilers. A comparison between fossil-fueled and fossil-fueled/PV MG scenarios reveals that, while the latter perform slightly better when only electric efficiencies are considered, the opposite is true when total efficiencies are taken into account, as PV does not contribute to heat generation and therefore part of the thermal load of the network has to be satisfied through electric boilers.

Finally, even with a moderate amount of microgrid capacity (8% of the total capacity in the Netherlands), the reliability (intended as long-run average availability) of the bulk power system is higher. Scenarios including MGs offer greater reliability because the generating capacity of a few, large natural gas CC and CT units in the non-MG scenarios is substituted with a great number of small generators with lower forced outage rates.

Several extensions of our regional assessment methodology are possible. For example, it would be useful to include a direct quantification of social sustainability, even though one of our sensitivity analyses showed this would not alter the main conclusions of the analysis. Another interesting addition would be the estimation of the external costs of pollutants for the regional grid accounting for specific, context dependent variables. As pointed out, both extensions would require making reference to specific locations and populations whose views and willingness to pay can be surveyed. Finally, it would be important to include other aspects of power reliability (in particular, customer outages arising at the distribution level) and power quality in the analysis.

Acknowledgements

Funding for this research was provided by the National Science Foundation under NSF-EFRI grant 0835879. The authors gratefully acknowledge useful comments by two anonymous referees. Opinions and errors are the responsibility of the authors.

Nomenclature

Indices of the optimization model

- i node in the network
- ik arc linking node i to node k
- j aggregate plant (step)
- m voltage loop

Indices of the reliability valuation model

- i node in the network
- j aggregate plant (step)
- w season of the year (winter/summer)
- z component of the MONA

Sets of the optimization model

I	set of all nodes
J	set of aggregate plants, differing in location, ownership, fuel type and cost
J_i	set of aggregate plants at node i
M	set of Kirchhoff's voltage loops
A_i	set of nodes adjacent to node i
M_m	ordered set of links ik in voltage loop m

Parameters of the optimization model

CO_2	CO_2 price, €/ton
L_i	power demand at node i, MW
R_{ik}	reactance on arc ik
S_{ikm}	± 1 depending on the orientation of arc ik in loop m
$Loss_{ik}$	resistance loss coefficient on arc ik, 1/MW
T_{ik}	maximum transmission capacity on arc ik, MW
MC_{ij}	marginal cost for generation at node i and step j, €/MWh
E_{ij}	CO_2 emission rate at node i and step j, ton/MWh
Cap_{ij}	maximum generation capacity at node i and step j, MW

Parameters of the reliability valuation model

Cap_{ij}	maximum generation capacity at node i and step j, MW
FOR_{ij}	forced outage rate for individual plants at node i and step j
N_{ij}	number of individual power plants at node i and step j
L_z	power demand of the z^{th} component of the MONA, MW
Cap_w	expected generating capacity in season w, MW
$Wind_w$	wind generation in season w, MW
λ_w	parameter of the exponential approximation to wind distribution in season w, MW

Decision variables of the optimization model

f_{ik}	export flow from node i to node k, MW
gen_{ij}	generation at node i by aggregate plant j, MW

Decision variables of the reliability valuation model

μ_z	mean of the z^{th} component of the MONA, MW
σ_z^2	variance of the z^{th} component of the MONA, $(MW)^2$
p_z	weight of the z^{th} component of the MONA

Thermodynamic variables

$\dot{W}$	annual electric power load of the network, MWh
$\dot{Q}$	annual heat load of the network, MWht
η_b	efficiency of the boilers
η_e	annual energetic electric efficiency of the network
η_{tot}	annual energetic total efficiency of the network
ζ_e	annual exergetic electric efficiency of the network
ζ_{tot}	annual exergetic total efficiency of the network
φ_e	exergy to energy ratio of fuels used for electricity generation in the network
$\dot{E}_S^Q$	exergy content of the heat load, MWh
$\dot{E}_{NG}$	exergy flow rate of natural gas, MJ/s*hour
$\dot{M}_{NG}$	mass flow rate of natural gas, kg/s
H_{NG}	Lower Heating Value of natural gas, MJ/kg
φ_{NG}	exergy to energy ratio of natural gas

References

[1] Market integration: coupling of the European electricity markets [Internet]. Available from: http://www.tennettso.de/pages/tennettso_en/Press/Information_Material/PDF/100478_TEN_Brochure_marktkoppeling.pdf [accessed 2011 Jun 24].

[2] CWE Market integration [Internet]. Available from: http://www.apxendex.com/index.php?id=186 [accessed 2011 Jun 24].

[3] Report of the United Nations World Commission on Environment and Development. Our common future [Internet]. Available from: http://www.un-documents.net/wced-ocf.htm [accessed 2011 Jun 24].

[4] Hobbs, B.F., Meier, P. Energy decisions and the environment: a guide to the use of multicriteria methods. Kluwer Academic Publishers; 2000.

[5] Lebre LaRovere, E., Borghetti Soares, J., Basto Oliveira, L., Lauria, T. Sustainable expansion of electricity sector: sustainability indicators as an instrument to support decision making. Renewable and Sustainable Energy Reviews 2010; 14: 422-9.

[6] Giannantoni, C., Lazzaretto, A., Macor, A., Mirandola, A., Stoppato, A., Tonon, S. et al. Multicriteria approach for the improvement of energy systems design. Energy 2005; 30(10): 1989-2016.

[7] Wang, J., Jing, Y., Zhang, C., Zhao, J. Review on multi-criteria decision analysis aid in sustainable energy decision making. Renewable and Sustainable Energy Reviews 2009; 13: 2263-2278.

[8] Maruyama, Y., Nishikido, M., Iida, T. The rise of community wind power in Japan: enhanced acceptance through social innovation. Energy Policy 2007; 35(5): 2761-2769.

[9] Gallego Carrera, D., Mack, A. Sustainability assessment of energy technologies via social indicators: results of a survey among European energy experts. Energy Policy 2010; 38: 1030-1039.

[10] Turvey, R., Anderson, D. Electricity economics: essays and case studies. Baltimore: Johns Hopkins University Press; 1977.

[11] ExternE: externalities of energy, Vol.1; 1995 [Internet]. Available from: http://www.externe.info/ [accessed 2011 Jun 24]

[12] Ottinger, R.L., Wooley, D., Robinson, N., Hodas, D., Babb, S. Environmental costs of electricity. New York: Oceana Publications; 1990.

[13] Hohmeyer, O., and Ottinger, R.L., editors. External environmental costs of electric power: analysis and internalization. Proceedings of a German-American Workshop; 1990, October 23-25; Ladenburg, FRG. New York: Springer-Verlag; 1991.

[14] Gil, H.A. Models for quantifying the economic benefits of distributed generation. IEEE Transactions on Power Systems 2008; 23(2): 327-35.

[15] Tsikalakis, A.G., Hatziargyriou, N.D. Environmental benefits of distributed generation with and without emissions trading. Energy Policy 2007; 35(6): 3395-409.

[16] Hadley, S.W., Van Dyke, J.W., Poore III, W.P., Stovall, T.K. Quantitative assessment of distributed energy resource benefits [Internet]. Oak Ridge National Laboratory, Engineering Science and Technology Division. Available from: http://www.ornl.gov/∼webworks/cppr/y2001/rpt/116227.pdf. [accessed 2011 Jun 24].

[17] U.S. Department of Energy. The potential benefits of distributed generation and rate-related issues that may impede their expansion [Internet]. Available from: http://www.ferc.gov/legal/fed-sta/exp-study.pdf. [accessed 2011 Jun 24]

[18] Alanne, K., Sari, A. Distributed energy generation and sustainable development. Renewable and sustainable energy reviews 2006; 10(6): 539-58.

[19] Firestone, R., Marnay, C., Maribu, K.M. The value of distributed generation under different tariff structures. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2006 May. Report No.: LBNL-60589. Contract No.: DEAC0205CH11231. Sponsored by the US Department of Energy.

[20] Siddiqui, A.S., Marnay, C., Edwards, J.L., Firestone, R., Ghosh, S., Stadler, M. Effects of a carbon tax on microgrid combined heat and power adoption. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2004 Oct. Report No.: LBNL-51771. Contract No.: DEAC0376SF00098. Sponsored by the US Department of Energy.

[21] Marnay, C., Lai, J., Stadler, M., Siddiqui, A. Added value of reliability to a microgrid: simulations of three California buildings. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Tech-

nologies Division; 2009 Apr. Report No.: LBNL-1853E. Contract No.: DEAC0205H11231. Sponsored by the US Department of Energy.
[22] Yi, H., Hau, J.L., Ukidwe, N.U., Bakshi, B.R. Hierarchical thermodynamic metrics for evaluating the environmental sustainability of industrial processes. Environmental Progress 2004; 23(4): 302-14.
[23] Frangopoulos, C.A., Keramioti, D.E. Multi-criteria evaluation of energy systems with sustainability considerations. Entropy 2010; 12(5): 1006-20.
[24] Frangopoulos, C.A., von Spakovksy, M.R. A global environomic approach for energy systems analysis and optimization. Proceedings of the Energy Systems and Ecology Conference; 1993 July 5-9; Cracow, Poland. p.123-44.
[25] von Spakovksy, M.R., Frangopoulos, C.A. The environomic analysis and optimization of a gas turbine cycle with cogeneration. American Society of Mechanical Engineers (ASME) 1994; 33: 15-26.
[26] Rosen, M. Energy and exergy-based comparison of coal-fired and nuclear steam power plants. Exergy 2001; 1(3): 180-92.
[27] Zvolinschi, A., Kjelstrup, S., Bolland, O., van der Kooi, H.J. Exergy sustainability indicators as a tool in industrial ecology. Journal of Industrial Ecology 2007; 11(4): 85-98.
[28] Billinton, R., Allan, R.N. Reliability evaluation of power systems: concepts and techniques. New York: Plenum Press; 1996.
[29] Stoll, H.G. Least-cost electric utility planning. New York: John Wiley and Sons; 1989.
[30] Wood, A.J., Wollenberg. B.F. Power generation operation and control. New York: John Wiley and Sons; 1996.
[31] Marnay, C. Microgrids and heterogenous power quality and reliability. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2008 Jul. Report No.: LBNL-777E. Contract No.: DEAC0205CH11231. Sponsored by the US Department of Energy.
[32] Chowdhury, S., Chowdhury, S.P., Crossley, P. Microgrids and active distribution networks. London: The Institution of Engineering and Technology; 2009.
[33] Council of European Energy Regulators. Fourth benchmarking report on quality of electricity supply 2008 [Internet]. Available from: http://www.autorita.energia.it/allegati/pubblicazioni/C08-EQS-24-04_4th_Benchmarking_Report_EQS_10-Dec-2008_re.pdf [accessed 2011 Jun 24].
[34] Hobbs, B.F. Models for integrated resource planning by electric utilities. European Journal of Operational Research. 1995; 83(1): 1-20.
[35] Hobbs, B.F., Rijkers, F.A.M. Modeling strategic generator behavior with conjectured transmission price responses in a mixed transmission pricing system I: formulation, IEEE Transactions on Power Systems 2004; 19(2): 707-17.
[36] Hobbs, B.F., Drayton, G., Bartholomew Fisher, E., Lise, W. Improved transmission representations in oligopolistic market models: quadratic losses, phase shifters, and DC lines. IEEE Transactions on Power Systems 2008; 23(3): 1018-29.
[37] Energy Research Centre of the Netherlands. COMPETES input data [Internet]. Available from: http://www.ecn.nl/fileadmin/ecn/units/bs/COMPETES/cost-functions.xls [accessed 2011 Jun 24]
[38] International Energy Agency. Energy Prices and Taxes, energy end-use prices in national currencies, vol.2. Paris: International Energy Agency; 2010.
[39] International Energy Agency. Electricity Information. Paris: International Energy Agency; 2010.
[40] European Network of Transmission System Operators for Electricity. Hourly load values for a specific country for a specific month [Internet]. Available from: https://www.entsoe.eu/index.php?id=137 [accessed 2011 Jun 24].
[41] International Energy Agency Energy Conservation in Buildings and Community Systems, Annex 42 [Internet]. Standard European Electrical Profiles. 2006. Available from: http://www.ecbcs.org/docs/Annex_42_European_Electrical_Standard _Profiles_Annex_42_September_2006.zip [accessed 2011 Jun 24].
[42] De Vries, L.J. Generation adequacy: helping the market do its job. Utilities Policy 2007; 15(1): 20-35.
[43] Gross, G., Garapic, N.V., McNutt, B. The mixture of normals approximation technique for equivalent load duration curves. IEEE Transactions on Power Systems 1988; 3(2): 368-74.
[44] North American Electric Reliability Corporation. 2005-2009 Generating Availability Report [Internet]. Available from: http://www.nerc.com/page.php?cid=4|43|47 [accessed 2011 Jun 24].
[45] Energy and Environmental Analysis, Inc. Distributed generation operational reliability and availability database. Executive summary report [Internet]. Available from: http://files.harc.edu/Sites/GulfCoastCHP/Publications/Distributed OperationalReliability.pdf [accessed 2011 Jun 24].
[46] Hargreaves, J.J., Hobbs, B.F. Optimal commitment and dispatch with uncertain wind generation using stochastic dynamic programming. Manuscript, Department of Geography & Environmental Engineering, Johns Hopkins University, 2010.
[47] AEA Technology. Environmental Product Declaration of Electricity from Torness Nuclear Power Station - a technical report [Internet]. Available from: http://www.british-energy.com/documents/EPD_Doc_-_Final.pdf [accessed 2011 Jun 28].
[48] Spath, P.L., Mann, M.K., Kerr, D.R. Life cycle assessment of coal fired power production. Golden (CO): National Renewable Energy Laboratory; 1999 June.
[49] Spath, P.L., Mann, M.K. Life cycle assessment of a natural gas combined-cycle power generation system. Golden (CO): National Renewable Energy Laboratory; 2000 September.
[50] Kaewboonsong, W., Kuprianov, V.I., Chovichien, N. Minimizing fuel and environmental costs for a variable-load power plant (co-)firing fuel oil and natural gas. Part 1. Modeling of gaseous emissions from boiler units. Fuel processing technology 2006; 87: 10851094.
[51] Boudghene Stambouli, A., Traversa, E. Solid oxide fuel cells (SOFCs): a review of an environmentally clean and efficient source of energy. Renewable and Sustainable Energy Reviews 2002; 6: 433-455.
[52] Greenhouse Gas Technology Center - Southern Research Institute. Environmental technology verification report. Combined heat and power at a commercial supermarket - Capstone 60 kW microturbine CHP system [Internet]. Available from: http://www.capstoneturbine.com/_docs/EPA-C60testreport.pdf [accessed 2011 Jun 27].
[53] Pipattanasomporn, M., Willingham, M. White paper on distributed generation [Internet]. Available from: http://www.idc-online.com/technical_references/pdfs/electrical_engineering/Distributed %20generation.pdf [accessed 2011 Jun 27].
[54] EcoSenseWeb [Internet]. Available from: http://ecosenseweb.ier.uni-stuttgart.de/.
[55] NEEDS - New Energy Externalities Developments for Sustainability. Report on the procedure and data to generate averaged/aggregate data, RS3a-D1.1; 2008 [Internet]. Available from: http://www.needs-project.org/2009/ [accessed 2011 Jun 24].
[56] Bejan, A., Tsatsaronis, G., Moran, M. Thermal design and optimization. New York: John Wiley and Sons; 1996.

Sustainability and reliability assessment of microgrids in a regional electricity market

Chiara Lo Prete[a,*], Benjamin F. Hobbs[a], Catherine S. Norman[a], Sergio Cano-Andrade[b], Alejandro Fuentes[b], Michael R. von Spakovsky[b], Lamine Mili[c]

[a] *Johns Hopkins University, Department of Geography and Environmental Engineering, Baltimore, USA*
[b] *Virginia Polytechnic Institute and State University, Department of Mechanical Engineering, Blacksburg, USA*
[c] *Virginia Polytechnic Institute and State University, Department of Electrical and Computer Engineering, Blacksburg, USA*

Abstract

We develop a framework to assess and quantify the sustainability and reliability of different power production scenarios in a regional system, focusing on the interaction of microgrids with the existing transmission/distribution grid. The Northwestern European electricity market (Belgium, France, Germany and the Netherlands) provides a case study for our purposes. We present simulations of power market outcomes under various policies and levels of microgrid penetration, and evaluate them using a diverse set of metrics. This analysis is the first attempt to include exergy-based and reliability indices when evaluating the role of microgrids in regional power systems. The results suggest that a power network in which fossil-fueled microgrids and a price on CO_2 emissions are included has the highest composite sustainability index.

Keywords: Microgrids, sustainability, reliability, Northwestern Europe, exergy, economics, air pollution, multi-criteria decision making.

1. Introduction

A microgrid (MG) is a localized grouping of electric and thermal loads, generation and storage that can operate in parallel with the grid or in island mode and can be supplied by renewable and/or fossil-fueled distributed generation. We quantify the sustainability and reliability of MGs in a regional power market in terms of multiple indices for the regional grid. The setting is the Northwestern European electricity market (Belgium, France, Germany and the Netherlands). This is a regional network whose national markets already influence each other strongly and have taken steps to integrate even further into a single market. Since 2006, for example, the Netherlands, France and Belgium have coupled their electricity exchanges through the Trilateral Market Coupling (TLC), ensuring the convergence of spot electricity prices in the three countries. In November 2010, the TLC was replaced by the Central Western European Market Coupling (CWE), which also includes Germany [1] [2].

Sustainable development is often defined as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs" [3]. Translating this definition into quantifiable criteria that can be used to compare alternative power systems has proven difficult. For this reason, several authors have adopted a multi-criteria (or multiple objective) approach. The function of multi-criteria analysis is to communicate tradeoffs among conflicting criteria and to help users quantify and apply value judgments in order to recommend a course of action [4]. In this manner, a range of dimensions of sustainability can be considered, while allowing stakeholder groups to have different priorities among the criteria. This method has been used, for example, to assess the tradeoffs in power system planning [5] and to evaluate the sustainability of power generation [6].

The main contribution of this paper is the quantification of the sustainability and reliability of alternative power generation paths in a regional system with a diverse set of metrics. We explicitly simulate the impacts of a generation investment decision on operations and investment elsewhere in the grid, as evaluation of the net sustainability impacts of a decision should consider how a given investment choice propagates through the system. Our approach does not rely on multi-objective optimization; it presents instead a multi-criteria assessment through the use of indicators, which are calculated based on the results of a single-objective optimization model and a reliability model.

Among the commonly used four dimensions to evaluate the sustainability of energy supply systems (social, economic, technical and environmental) [7], the analysis emphasizes the latter three. In terms of microgrid impact on social sustainability, several areas commonly cited as important are equity, community impacts, level of participation in decision making and health impacts. The first three depend on how a given microgrid is owned and managed. In general, it is plausible that the increased impact that members of the microgrid-served pop-

*Corresponding author at Johns Hopkins University, Department of Geography and Environmental Engineering, 3400 North Charles Street, 313 Ames Hall. Baltimore, MD, 21218, USA. Email address: chiara.lo.prete@jhu.edu. Phone number: 410-516-5137. Fax number: 410-516-8996.

ulation could have on ownership and management decisions, relative to populations served by conventional utilities, would count as a positive impact on social sustainability. Additionally, shared community values may lead some stakeholders to value microgrids that use renewable energy more highly than either microgrids that do not or larger systems in which the community has little choice about the source of electricity [8]. Increased security of supply associated with microgrids may also offer social as well as economic benefits within and outside the community served by a microgrid. Finally, microgrid operation may create jobs that offer social sustainability gains for the local community.

On the other hand, microgrids may have negative effects on residents' quality of life, if they increase the level of noise or have aesthetic impacts on the landscape [9]. Health impacts of a microgrid may also be negative, as microgrids are likely to have generation and thus pollution closer to the populations they serve than conventional distribution networks. How risks to life and health associated with local air pollution compare with the ones from a conventional utility source will be very population, site and technology specific.

While we can speculate on the likely direction of these impacts for the power system modeled in this paper, it is difficult to quantify them without reference to a specific location and population whose views and willingness to pay can be surveyed or estimated. On the contrary, the methodology used in our analysis aims at assessing the broader impacts of alternative power generation paths on a regional power system. For this reason, no direct quantification of social sustainability is offered in our study. However, to account indirectly for this dimension we perform a sensitivity analysis on the results in order to assess whether and how the introduction of a social sustainability index would alter our conclusions.

We consider six alternative scenarios for satisfying the electric power and thermal needs of a regional power market, and we characterize their sustainability and reliability using four sets of indicators. The scenarios are various combinations of microgrid implementation (with and without MGs), microgrid generating mix (fossil-fueled only, or fossil-fueled and renewable) and CO_2 policies (with and without a price on CO_2 emission allowances). The first set of indices is based on CO_2 and conventional air pollutant emissions (NO_x and SO_x). The second one emphasizes economic sustainability in terms of total generation costs [10] and accounts for externalities of electricity generation. Externalities can be defined as "the costs and benefits which arise when the social or economic activities of one group of people have an impact on another, and when the first group fails to fully account for their impacts" [11]. In the 1990s the importance of environmental costs as an input to the planning and decision processes of electric power generation systems was recognized in several studies [12] [13]. The third set of indices is based on thermodynamic energy and exergy based efficiencies, while the fourth considers effects on bulk power system reliability.

Economic and environmental analyses of power systems including distributed generation are common (see, for example, [14] and [15]). Several studies assess the potential benefits of distributed generation [16] [17] and evaluate its impact on sustainable development [18]. Others focus directly on the economic and regulatory issues of MG implementation [19], on the implications of environmental regulation on MG adoption [20], and on the improvement in power reliability provided to different types of buildings by the installation of a MG [21]. In contrast, neither thermodynamic analyses considering the interaction of MGs with existing regional power systems nor the effect of MG deployment on system reliability have been previously published, to the best of our knowledge.

We include exergy because an analysis relying on first law efficiency alone does not consider to what degree the outputs of a power plant are useful. For example, electricity is more valuable than steam, one of the typical by-products of power production, because the latter is characterized on a per unit energy basis by a lower value of exergy than electricity. Therefore, not all outputs should be valued in the same way: outputs having a higher quality or exergy per unit energy (like electricity) should have a higher unit price than those having a lower quality or exergy per unit energy (like steam) because the former possess a greater ability to do work. In contrast, when the second law of thermodynamics is disregarded, the difference in quality of the various energy outputs is not considered and cannot be effectively compared for different energy conversion processes.

Thus, the use of exergy-based indicators can help decision makers to improve the effectiveness of energy resource use in a given system. Such indicators have been widely adopted in the sustainability literature. Yi et al. [22] use thermodynamic indices to assess the sustainability of industrial processes. Frangopoulos and Keramioti [23] evaluate the performance of different alternatives to meet the energy needs of an industrial unit, taking into account several aspects of sustainability. von Spakovsky and Frangopoulos [24] [25] use an environomic (thermodynamic, environmental and economic) objective for the analysis and optimization of a gas turbine cycle with cogeneration. Rosen [26] presents a thermodynamic comparison of a coal and a nuclear power plant on the basis of exergy and energy. Zvolinschi et al. [27] develop three exergy-based indices to assess the sustainability of power generation in Norway.

In addition to sustainability, it is important to incorporate a reliability analysis in the decision process because of the positive impact that microgrids may have on power system reliability, and thereby on promoting their deployment. Therefore, we add reliability to our suite of indices and quantify it using the annual Loss of Load Probability (LOLP) and Expected Loss of Energy (ELOE) [28] [29]. The reliability of a power system is the probability that the system is able to perform its intended function (generation meets load), under a contractual quality of service, for a specified period of time. Reliability is quantified here using the concept of "long-run average availability" of the bulk power system (supply-demand balance), without consideration of dynamic system response to disturbances, which instead is the concept of "security" [30].

We do not consider aspects of power quality that may also be controlled within MGs. It has been argued that microgrids have the potential to deliver different degrees of power quality tailored for different customers' needs, as they may be employed to control power quality locally according to customers' requirements. This may prove to be more beneficial than providing a uniform level of quality and service to all customers without differentiating among their needs [31] [32]. However, the way in which microgrids may affect power quality in a regional grid is still under study and there are no definitive results. For this reason, we do not include power quality considerations in our analysis, though we note they should be addressed in future research.

We also do not consider customer outages arising at the subtransmission or distribution-level. However, it is worth noting that the majority of power interruptions experienced by customers in the countries we consider are not due to large events at the bulk level, but to more localized ones affecting the distribution system [33].

Section 2 describes our modeling approach, data and assumptions concerning alternative power systems (with and without MGs) and CO_2 policies. Section 3 presents the six scenarios considered in our analysis to satisfy the electric power and thermal needs of the Northwestern European electricity market. Section 4 describes the indicators chosen in this paper to assess the sustainability and reliability of the network. Section 5 discusses the results of the analysis, while Section 6 concludes.

2. Methodology and data

Two different models are used to quantify our indices. A regional power market model based on linear optimization methods [10] [34] provides the information necessary for the economic, environmental and thermodynamic indices; the model is presented in Section 2.1. A local reliability model based on convolution methods [28] [29], described in Section 2.2, is used instead to obtain the reliability indices.

2.1. Regional market simulation model

For the purposes of this paper, we represent the Northwestern European electricity market using COMPETES (Comprehensive Market Power in Electricity Transmission and Energy Simulator) [35]. Our version of COMPETES is a quadratically constrained model solved in ILOG OPL 6.3, using the optimizer Cplex12. COMPETES models twelve power producers in the four countries: eight of them are the largest ones in the region (Electrabel, Edf, Eon, ENBW, RWE, Vattenfall, Essent Nuon-Reliant), while the remaining four represent the competitive fringe in each country.

When no MGs are included, the electricity network is represented by fifteen nodes. Each of the seven main nodes (Krim, Maas and Zwol in the Netherlands; Merc and Gram in Belgium; one node in France and one in Germany) has generation capacity and load. A DC power flow model is used to represent a system in which four intermediate nodes are distinguished in both France (Avel, Lonn, Moul, Muhl) and Germany (Diel, Romm, Ucht, Eich); at these nodes, no generation or demand occurs (except for 2,000 MW of power exports to the UK at Avel). Three nodes representing groups of residential MGs are added to the model in the MG scenarios.

The nodes of the network are connected by twenty-eight high voltage transmission corridors (or arcs), each one with a maximum MW transmission capacity. The groups of MGs are connected to the transmission system by radial links at nodes Krim, Maas and Zwol in the Netherlands. While by assumption we are focusing on the impact of new microgrids in the Netherlands, to understand their impacts on the regional power grid it is necessary to consider the neighboring countries' bulk power markets. Of course, groups of microgrids could also be connected to nodes in other countries. However, we would then need to consider additional neighboring countries, such as Poland or the Iberian peninsula.

Computational convenience suggests starting the analysis with a competitive benchmark. Our application of COMPETES calculates a competitive equilibrium among power producers, which under the assumption of perfectly inelastic demand is equivalent to minimization of total generation costs. This is done for six representative hours in order to characterize the distribution of operating costs.

We include resistance losses on high voltage transmission flows to make the model more realistic because, on average, losses can contribute as much to spatial price variations as congestion does. Losses vary as a quadratic function of flow, using the DC formulation with quadratic losses in [36]. In the absence of other data, resistance loss coefficients, defined for the twenty-eight corridors of the network, are assumed to be proportional to reactance. Therefore, we set them equal to the reactance on each corridor times a constant α, whose value is chosen so that high voltage transmission losses are approximately equal to 2% of generation during the peak hours.

2.1.1. Model formulation

COMPETES is a short-run market simulation model using an optimization formulation: its objective function includes short-run marginal costs (i.e., fuel and other variable O&M costs) and disregards long-run retirement and entry decisions. For each MG and CO_2 policy scenario, we solve the model for six different periods of the year representing a variety of load and generation capacity conditions. The six periods are appropriately weighted by the number of hours in each period to estimate annual cost. The problem statement is as follows:

$$\min \sum_{i} \sum_{j \in J_i} (MC_{ij} + CO_2 E_{ij}) gen_{ij} \tag{1}$$

subject to:

$$\sum_{j \in J_i} gen_{ij} + \sum_{k \in A_i} [f_{ki}(1 - Loss_{ki} f_{ki}) - f_{ik}] \geq L_i \quad \forall i \in I \tag{2}$$

$$\sum_{ik \in M_m} R_{ik} S_{ikm} (f_{ik} - f_{ki}) = 0 \quad \forall m \in M \tag{3}$$

$$gen_{ij} \leq Cap_{ij} \quad \forall i \in I, \forall j \in J_i \tag{4}$$

$$f_{ik} \leq T_{ik} \quad \forall i, k \in I \tag{5}$$

$$f_{ik} \geq 0 \quad \forall i, k \in I \tag{6}$$

$$gen_{ij} \geq 0 \quad \forall i \in I, \forall j \in J_i \tag{7}$$

A complete list of variable and parameter definitions is provided in the nomenclature. The goal is to minimize the objective function expressed as the total generation costs given by equation 1, where a linear short-run cost of production is assumed. The decision variables are gen_{ij} (the generation from aggregated power plant j located at node i) and f_{ik} (the MW transmission flow from node i to a nearby node k that is directly connected to i by a transmission corridor).

Equation 2 accounts for Kirchhoff's Current Law (KCL), applied to each node of the network. f_{ik} is the export flow from node i to node k, while $f_{ki}(1\text{-}Loss_{ki} f_{ki})$ represents the import flow (net of losses) into node i from node k. Equation 3 represents Kirchhoff's Voltage Law (KVL) constraint, defined for each of the fourteen meshes (or loops) connecting the nodes. Equation 4 ensures that power generated at each node and each step is less than the available capacity at that location, while equation 5 constrains the transmission flow on a given arc. Equations 6 and 7 are nonnegativity restrictions.

When microgrids are included, their generation costs are added to equation 1. Since the groups of MGs are additional nodes with autonomous loads, one KCL constraint is added in the model for each MG node. However, no additional KVL is included because MGs are assumed to be radially connected to the grid. The power generated at each MG node must satisfy the capacity constraint (equation 4) and the non-negativity constraint (equation 7), and its flow to/from the grid must satisfy bounds 5 and 6.

2.1.2. Data

Simulations of power market outcomes are based on a modified version of the Energy Research Centre of the Netherlands (ECN) COMPETES database of transmission, demand and generation [37].

This provides a multi-step supply function (one step per aggregate power plant) for each node where power generation occurs. Using the information in [38] and [39], generation costs and capacity of the original fifteen nodes of the network in [37] have been updated to 2008 (a leap year). Our version of the database has also been modified to account for transmission resistance losses, exergetic and energetic efficiencies, and emissions.

In the scenarios including MGs, nine steps representing MG technologies (three for each node to which MGs are connected) have been added to the existing network. Generation costs, technology types and capacity for the MG nodes are obtained from the literature.

In line with [37], in the scenarios without MGs the capacity database does not include renewable and combined heat and power (CHP) generators. On the other hand, CHP capacity is installed at the MG nodes and we explicitly consider its contribution to the system.

Hourly loads in the four countries are based on [40] and refer to 2008. Since CHP and renewable generators are not included in the capacity database, their production is netted from the hourly electricity demand of the network in [40]. Hourly loads are organized in load duration curves (LDCs) and divided into six blocks: the first block averages the load of the first 100 hours, the second block of the following 900 hours, the third and fourth of the next 2,500 hours, the fifth of the next 2,284 hours, the sixth of the last 500 hours. The average electricity consumption of the residential customers in the MGs is based on the load profiles in [41]. Information on total capacity, dominant fuel type, energy efficiency, exergy calculations, marginal cost function and average CO_2, NO_x, SO_x emission rates for all the nodes in the network is available from the authors.

2.2. Reliability valuation model

In addition to the market simulation model, we develop a model to assess the reliability of the Dutch power system in two scenarios (with and without MGs). We consider the Dutch system alone for two reasons. First, we focus our analysis on the direct impact of MGs on the reliability in the country where they are installed. Second, the Netherlands is the most import-dependent of the four countries considered, and the adequacy of generating capacity to meet future energy needs has been extensively debated over the last decade [42]. We include two reliability indices, the LOLP and the ELOE. The LOLP of a power system is the expected number of hours of capacity deficiency in the system in a given period of time [29]. In our analysis, the LOLP is expressed in outage hours/10 years: an outage of 8 hours in 10 years is typically considered a reasonable reliability target in industrialized countries. The ELOE gives an indication of the amount of load that cannot be serviced in a given period of time and is expressed in MWh/yr [28].

In our model, 2008 summer and winter LDCs are approximated using the mixture of normals approximation (MONA) technique detailed in [43]. Given z = 1,..,Z independent normal random variables, each with mean μ_z, variance σ_z^2, and cumulative distribution function $\Phi(\cdot;\, \mu_z,\, \sigma_z^2)$, F(·) has a mixture of normals distribution with z components if

$$F(x) = \sum_z p_z \Phi(x; \mu_z, \sigma_z^2) \tag{8}$$

$$\sum_z p_z = 1; \quad 0 \le p_z \le 1 \tag{9}$$

where p_z is the weight of the z^{th} component. A LDC can be approximated by

$$LDC(x) = 1 - F(x) \tag{10}$$

For our purposes, a two-component mixture of normals provides an excellent approximation of the load duration curve; the weights, mean and variances in equation 8, different for winter and summer loads, are obtained by minimizing the squared difference between the original and approximated distributions, with higher penalties on deviations during peak periods. In the reliability analysis, loads include CHP and renewable production.

We define the expected available capacity and the variance of available capacity of supply function step j at node i as:

$$E(Cap_{ij}) = [Cap_{ij}(1 - FOR_{ij})] \tag{11}$$

$$Var(Cap_{ij}) = \frac{1}{N_{ij}}[(Cap_{ij})^2 FOR_{ij}(1 - FOR_{ij})] \qquad (12)$$

where N_{ij} is the number of individual power plants at aggregate step j and FOR_{ij} is the forced outage rate of each individual power plant in step j. These expressions are based on a binomial distribution approximation, assuming N_{ij} independent generators in the step. The forced outage rates of the central generators are obtained for each technology type from [44]. In the absence of other specific data, we use [45] for the MG technologies. We assume that summer and winter available generating capacity follows a normal distribution, with mean equal to the total expected generating capacity and variance equal to the sum of variances at all steps of the supply function.

In the reliability analysis, power generation capacity includes an estimate of the CHP capacity in the Netherlands. It also accounts for the maximum feasible flow of power imports to the Netherlands from neighboring countries, assuming that under highly stressed conditions the Dutch system will maximize imports. The maximum flow is based on the COMPETES simulations under peak demand conditions.

Since wind power accounted for about 5% of 2008 electricity net production in the Netherlands [39], its production should be netted from electricity demand in our reliability analysis. The time series of wind generation over 15-minute intervals in one representative year [46] suggests that the density function of wind power generation in the Netherlands may be adequately approximated by an exponential distribution. This is confirmed by the non rejection of the Kolmogorov-Smirnov test of the exponential distribution of this sample at a 1% significance level. We use two different exponential approximations, one for the winter and one for the summer, with parameter λ_w equal to the average wind production in the Netherlands in the two seasons (556.5 MW in the summer and 378 MW in the winter, based on [46]).

In season w, the LOLP of each component of the normal mixture approximation z ($\mathrm{LOLP_{w,z}}$) is defined as

$$\begin{aligned} LOLP_{w,z} &= Prob(L_z - Cap_w - Wind_w \geq 0) \\ &= \int_0^\infty f_{L_z - Cap_w}(x) F_{Wind_W}(x)dx \end{aligned} \qquad (13)$$

where x represents the value of the thermal generation capacity deficit ($L_z - Cap_w$), $f_{L_z - Cap_w}(x)$ is the normal density function of ($L_z - Cap_w$) evaluated at x, and F_{Wind_W}(x) is the exponential cumulative distribution function of $Wind_w$ evaluated at x. We can express the $\mathrm{LOLP_{w,z}}$ as a product of functions because, according to [46], wind generation is largely independent of load in that area of Europe. The four values of $\mathrm{LOLP_{w,z}}$ (one for each season and each of the two components of our normal mixture approximation) are appropriately weighted by the probabilities p_z and the number of hours in each season to estimate the annual LOLP.

In season w, the ELOE of each component of the normal mixture approximation z ($\mathrm{ELOE_{w,z}}$) is defined as:

$$\begin{aligned} ELOE_{w,z} &= \int_0^\infty \int_0^x f_{L_z - Cap_w}(x) f_{Wind_W}(y)(x - y)dydx \\ &= \int_0^\infty f_{L_z - Cap_w}(x)[x + \tfrac{1}{\lambda_w}(e^{-\lambda_w x} - 1)]dx \end{aligned} \qquad (14)$$

Table 1: Characteristics of the network

Annual electric power load (TWh/yr)	1,104
Thermal load (MWht/yr)	5,909,115
Exergy content of the thermal load (MWh/yr)	2,282,768
Boiler capacity displaced by the MGs in Scenarios 2 and 5 (MW)	1,132
Boiler capacity displaced by the MGs in Scenarios 3 and 6 (MW)	895
Efficiency of the boilers	0.90
Peak power generating capacity (MW)	233,511

Similarly to the $\mathrm{LOLP_{w,z}}$, each $\mathrm{ELOE_{w,z}}$ is appropriately weighted by the probabilities p_z and the number of hours in each season to estimate the annual ELOE.

3. Description of the scenarios

We consider six alternative scenarios to satisfy the electric power and thermal needs of the Northwestern European electricity market. In every scenario we simulate six representative hours, one for each block defined in section 2.1.2. Annual results are obtained by averaging the hourly results by the number of hours in each block. The scenarios can be described as follows.

- *Scenario 1: no MG, no CO_2 price.* This scenario assumes that no MG operates in the Northwestern European power market and there is no price on CO_2 emissions. The characteristics of the network are summarized in Table 1. The only thermal load we consider is the one of the customers that could potentially be served by MGs; this is a thermal load of 5.9 TWht/yr, met by natural gas fueled boilers in this scenario and supplied to the residential district as saturated steam at p = 20 bar.

- *Scenario 2: MG, fossil-fueled generation technologies, no CO_2 price.* This scenario assumes that fifty residential fossil-fueled MGs operate in the Netherlands, connected to nodes Krim (16 MGs), Maas (17 MGs) and Zwol (17 MGs), and there is no price on CO_2 emissions. Each residential MG has a 24 MW generating capacity and serves about 30,000 customers. The generating mix at every MG node includes Solid Oxide Fuel Cells (SOFCs), natural gas microturbines (MTs) and diesel reciprocating engines (REs). The total capacity installed in the three MGs represents about 8% of the generating capacity in the Netherlands, and about 0.5% of the generating capacity of the entire regional grid. The assumed characteristics of the three MG nodes are summarized in Table 2. The annual electric power and thermal load of the network at the consumer voltage level are the same as in Scenario 1, in line with our zero elasticity assumption. However, the load at the bulk power level will be lower because MGs generate power closer to the consumers, lowering the transmission losses of the network. The thermal load (5.9 TWht/yr) is entirely satisfied by the CHP generating technologies installed at the MG level.

Table 2: Characteristics of the MG nodes

Annual electric power load (MWh/yr)	4,643,223
Thermal load (MWht/yr)	5,909,115
Exergy content of this thermal load (MWh/yr)	2,282,768
Thermal load satisfied by the MGs in Scenarios 3 and 6 (MWht/yr)	3,948,252
Thermal load satisfied by boilers in Scenarios 3 and 6 (MWht/yr)	1,960,863
Peak power generating capacity (MW)	1,330
of which:	
SOFCs or PV system/battery	*20%*
Natural gas MTs	*40%*
Diesel REs	*40%*

Table 3: Generating capacity in the network by fuel

	Scenario 1 and 4 No MGs		Scenario 2 and 5 MGs Fossil fuels only		Scenario 3 and 6 MGs Fossil fuels + PV	
Fuel	MW	share	MW	share	MW	share
Nuclear	101,583.5	43.5%	101,583.5	43.5%	101,583.5	43.3%
Coal	72,437.7	31.0%	72,437.7	31.0%	72,437.7	30.8%
Natural gas	38,073.0	16.3%	37,671.0	16.1%	37,432.7	15.9%
Oil	15,549.9	6.7%	16,069.5	6.9%	16,069.5	6.8%
Hydro	4,722.2	2.0%	4,722.2	2.0%	4,722.2	2.0%
Waste	1,144.3	0.5%	1,144.3	0.5%	1,144.3	0.5%
PV	-	-	-	-	1,638.4	0.7%
Total	233,510.6		233,628.1		235,028.2	

When MGs are present, the hourly load of the system at the bulk level is reduced by 1,212 MW in the peak period (first load block). This amount is equal to the maximum hourly load of the three MG nodes at the consumer voltage level (1,036 MW, occurring during winter peak hours), plus 2% of avoided transmission losses on that load and a 15% reserve margin. We assume that 1,057 MW less of central system natural gas-fired combined cycle (CC) plant would be built if MGs operate in the system, so this amount is subtracted from this type of generating capacity operating at the three Dutch nodes in the MG scenarios. We subtract only CC-type generators because we assume this type of capacity is the most recent central station thermal capacity constructed in the system. In addition, a peaking (combustion turbine - CT) capacity equal to 15% of that amount (155 MW) is assumed to no longer be needed as a reserve margin.

- *Scenario 3: MG, fossil-fueled and photovoltaic generation technologies, no CO_2 price.* This scenario is similar to the previous one. However, the power generation mix at each MG node is different and includes solar photovoltaic (PV), natural gas microturbines (MTs) and diesel reciprocating engines (REs) (Table 2). PV does not generate pollutant emissions during operation and does not contribute to heat generation; as a result, the thermal load of the MG customers (5.9 TWht/yr) is satisfied partially by CHP and partially by natural gas fueled boilers. Assessing the reliability of a system including renewable generators goes beyond the scope of our analysis; for this reason, we assume the same reliability of Scenario 2, although this might represent an optimistic estimate. Table 3 details the share of generating capacity by fuel in the regional grid.
- *Scenario 4: no MG, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 1 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.
- *Scenario 5: MG, fossil-fueled generation technologies, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 2 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.
- *Scenario 6: MG, fossil-fueled and photovoltaic generation technologies, CO_2 = 25 €/ton.* This Scenario is the same as Scenario 3 in terms of loads, generating capacity and efficiencies, but it also includes a price on CO_2 emissions of 25 €/ton.

4. Indicators

We chose our indicators based on [23] to assess different aspects of economic, technical and environmental sustainability. We also include two indicators commonly used in the literature to measure power system adequacy [28]. The indicators are classified into four groups.

4.1. Environmental Indicators

The three environmental indicators are:

1. *Annual emissions of CO_2* (Mton/yr)
2. *Annual emissions of NO_x*(kton/yr)
3. *Annual emissions of SO_x*(kton/yr)

We consider the pollutant emissions produced by the power plants operating in the network, as well as by the natural gas fueled boilers, when these operate to satisfy part or all of the heat load of the network. We also include an estimate of the complete fuel chain emissions for nuclear, coal and natural gas power plants, representing the bulk of generating technologies in the regional network (Table 3). For nuclear power plants, we include typical CO_2, NO_x and SO_x emissions calculated on a lifecycle basis in [47]. We increase the emissions from coal and natural gas generators to account for the ones occurring in the fuel production, transport, and disposal portions of the fuel cycle. This is done using the values detailed in [48] and [49]. It is important to emphasize that our goal is not to perform a detailed life-cycle analysis of all power plants operating in the regional grid, which would require the use of information that is not readily available, but to provide an estimate of the life-cycle emissions of the bulk of generating capacity.

Scenarios 1, 3, 4 and 6 include emissions from power generation and boilers (in addition to estimated life-cycle emissions for nuclear, coal and natural gas power plants). On the contrary, in Scenarios 2 and 5 the only pollutant emissions considered are due to the power plants operating in the network. There are no emissions from boilers in this case, as the heat requirement of the microgrids is entirely provided by their CHP technologies. The emission rates of the boilers are 0.606 ton CO_2/MWht and 0.00061 ton NO_x/MWht [50]. The emission rates for the regional grid and MG nodes are provided in Tables 4 and 5. It is worth emphasizing that the emission rates shown in Table 4 do not refer to modern plants only, but are averages of different types of existing plants in the power generating park of the four countries. The existing capacity is dominated by less efficient steam plants.

Table 4: Average emission rates in the network by fuel

Fuel	CO_2	NO_x	SO_x
Natural gas	0.57	0.0004	1.94e-06
Coal	0.99	0.0016	0.0021
Waste	0.63	0.0015	0.0020
Oil	0.73	0.0018	0.0016

Note: emission rates are in ton/MWh power generated. Values are averages of existing generating technologies in the network. Source: ECN.

Table 5: Emission rates in the MGs by technology

Technology	CO_2	NO_x	SO_x	Source
SOFCs	0.513	-	-	[51]
Gas MTs	0.700	0.000068	0.000003	[52]
Diesel REs	0.651	0.00991	0.000206	[53]

Note: emission rates are in ton/MWh power generated.

4.2. Economic Indicators

The two economic indicators are:

4. *Annualized capital costs and variable costs* (€/yr). In Scenarios 1 and 4, the capital cost impact is given by the annualized costs of the natural gas combined cycle and combustion turbine generation that would not be necessary in the MG scenario, plus the cost of the boiler capacity. We only consider the cost of units potentially replaced by MGs, as the one of other units represents a fixed cost in all scenarios and therefore can be disregarded, since it won't affect the differences among the systems, which is what determines the ranking of the scenarios. The annualized capital costs are computed by multiplying the current value of capital by an annualization factor $\frac{r(1+r)^n}{(1+r)^n-1}$, where r is the discount rate and n is the useful life of the item. The assumptions used are given in Table 6.

   The economic impact also includes the variable costs of operation of each scenario. The costs of the CO_2 allowances are not included in the economic indices because they simply represent a money transfer from the power generators to the government.

   In Scenarios 2 and 5, we consider the annualized capital costs and operating variable costs of the new MG capacity.

Table 6: Economic data for Scenarios 1 and 4

Capital cost of CC capacity ($/kW)	1,200
Capital cost of CT capacity ($/kW)	1,000
Total unbuilt CC capacity (MW)	1,057
Total unbuilt CT capacity (MW)	155
Useful life of gas capacity (years)	20
Capital cost of boilers ($/kW)	240
Useful life of boilers (years)	20
Cost of natural gas (€/MBtu)	6.4
Discount rate	0.05
Exchange rate (€/US$)	0.724

In addition to these, Scenarios 3 and 6 include the costs for the boiler capacity needed to satisfy part of the heat load of the network. The characteristics of the MG technologies are given in Table 7.

Table 7: Characteristics of the MG technologies

Technology	Capital cost	Useful life (years)	Energetic efficiency
PV system	5,884 $/kW	20	81%
Lead-acid battery	435 $/kWh	10	90%
SOFCs	4,700 $/kW	10	50%
Gas MTs	2,500 $/kW	20	26%
Diesel REs	350 $/kW	20	34%

Note: the PV system includes PV array, inverter and charge controller.

5. *Annualized capital costs and variable costs, including environmental externalities* (€/yr). We include an additional term, the external environmental costs of the pollutants, among the variable operating costs of each scenario. We considered using an integrated assessment model like EcoSense Web [54] to evaluate the external costs of NO_x and SO_x. EcoSense allows estimation of external costs of energy technologies by taking account of specific, context dependent variables (e.g., geography, population density). In the context of our analysis, however, we do not make reference to specific sites of each of the many power plants whose output changes in at least one period in the market solutions. Furthermore, we do not have information on the technical parameters of all power plants modeled in our regional system (e.g., stack gas exit velocities), which would be needed as inputs to the EcoSense software. In the ECN database groups of power plants are aggregated into steps of supply functions at each node of the network, and only general characteristics of each step (e.g., aggregate capacity, average efficiency) are available. Therefore, it is not possible to calculate the external costs of NO_x and SO_x using EcoSense Web due to lack of technical data.

   In the absence of other information, we use the NO_x and SO_x country-specific values provided by the NEEDS project [55] to reflect the impacts of power generation. The tools developed in the framework of the NEEDS project do not calculate the damage and external cost due to CO_2, as this is not considered a pollutant but a greenhouse gas. Thus, for the external cost of CO_2 we instead use the value in [23]. External costs are calculated on all emissions, including the indirect ones related to the life-cycle of nuclear, coal and natural gas power plants. The addition of environmental costs allows us to assess the real cost of the pollutant emissions to the society, which cannot be done simply by introducing CO_2 allowances. On the other hand, counting both the external costs of pollution in the cost indices and emissions as separate pollution indices could be viewed as double counting. To account for this, we have performed a sensitivity analysis in Section 5.

4.3. Technical Indicators

The four technical indicators are

6. *Annual energetic electric efficiency of the network.* This indicator is obtained by dividing the annual power production by the annual fuel use for power production in each scenario.

7. *Annual energetic total efficiency of the network*

$$\eta_{tot} = \frac{\dot{W} + \dot{Q}}{\frac{\dot{W}}{\eta_e} + \frac{\dot{Q}}{\eta_b}} \tag{15}$$

The heat rate requirement $\dot{Q}$ is the same in all scenarios. However, in Scenarios 1 and 4 the thermal load has to be met with separate boilers. In Scenarios 2 and 5 the MGs produce heat, through cogeneration, to satisfy their load. Therefore, the second term in the denominator of equation 15 is excluded in these scenarios, because all the fuel necessary to produce both heat and power is already included in the first term. In Scenarios 3 and 6, however, PV does not contribute to heat generation, and as a result the heat load of the network is satisfied partially through CHP and partially through boilers. The second term in the denominator of equation 15 accounts only for the fuel use of the additional boilers needed in these scenarios.

8. *Annual exergetic electric efficiency of the network*

$$\zeta_e = \frac{\eta_e}{\varphi_e} \tag{16}$$

φ_e is the ratio of the total exergy of the annual fuel use for power production and its total energy.

9. *Annual exergetic total efficiency of the network*

$$\zeta_{tot} = \frac{\dot{W} + \dot{E}_S^Q}{\frac{\dot{W}}{\zeta_e} + \dot{E}_{NG}} \tag{17}$$

$$\dot{E}_{NG} = \dot{M}_{NG} \times H_{NG} \times \varphi_{NG} \tag{18}$$

For the reasons explained for indicator 7, the last term in the denominator is excluded in Scenarios 2 and 5, and included with reference to the additional boilers used to satisfy the heat load in Scenarios 3 and 6. $\varphi_{NG} = 1.042$ and $H_{NG} = 38.1$ MJ/kg. The indicators in section 4.3 are described in [56].

Table 8: Values of the indicators, No CO_2 scenarios

Indicator	Scenario 1 No MG	Scenario 2 MG Fossil fuel mix	Scenario 3 MG Fossil + PV mix
Ind.1 CO_2 (Mton/yr)	331.96	328.98	328.97
Ind.2 NO_x (kton/yr)	347.76	343.15	343.05
Ind.3 SO_x (kton/yr)	289.44	281.55	280.67
Ind.4 Cost (M€/yr)	15,291	15,180	15,808
Ind.5 Cost+Extern. (M€/yr)	25,832	25,648	26,268
Ind.6 Eff.En.El.	0.4584	0.4583	0.4585
Ind.7 Eff.En.Tot.	0.4595	0.4607	0.4606
Ind.8 Eff.Ex.El.	0.4134	0.4133	0.4135
Ind.9 Eff.Ex.Tot.	0.4580	0.4592	0.4590
Ind.10 LOLP (hours/decade)	7.70	5.53	5.53
Ind.11 ELOE (MWh/yr)	220.35	152.82	152.82

4.4. Reliability Indicators

The two reliability indicators are

10. *Annual LOLP* (outage hours/10 years)

11. *Annual ELOE* (MWh/year)

5. Results

The indicators are calculated based on the results of the optimization problem and the reliability valuation model described above. Indicator values for each scenario are shown in Table 8 and 9. To analyze the trend of the emissions from power generation alone, we disregard the CO_2 and NO_x emissions of the boilers, as well as the estimated life-cycle emissions of nuclear, coal and natural gas plants (Table 10).

5.1. Base case

In the scenarios without MGs, total emissions are higher than in the ones including MGs. This is because in the non-MG scenarios boilers are used to satisfy the entire load of the network, and thus contribute to the production of pollutant emissions. However, Table 10 shows that SO_x emissions from power generation are higher in the scenarios including MGs. This happens because in the MG scenarios some high SO_x power plants fueled by coal and oil increase their output to meet the load of the network, replacing the production of the unbuilt CC and CT

Table 9: Values of the indicators, CO_2=25 €/ton scenarios

Indicator	Scenario 4 No MG	Scenario 5 MG Fossil fuel mix	Scenario 6 MG Fossil + PV mix
Ind.1 CO_2 (Mton/yr)	318.26	314.60	314.51
Ind.2 NO_x (kton/yr)	339.45	334.70	334.52
Ind.3 SO_x (kton/yr)	280.01	271.17	270.24
Ind.4 Cost (M€/yr)	15,446	15,339	15,984
Ind.5 Cost+Extern. (M€/yr)	25,583	25,383	26,018
Ind.6 Eff.En.El.	0.4607	0.4608	0.4611
Ind.7 Eff.En.Tot.	0.4618	0.4633	0.4631
Ind.8 Eff.Ex.El.	0.4155	0.4155	0.4158
Ind.9 Eff.Ex.Tot.	0.4603	0.4617	0.4616
Ind.10 LOLP (hours/decade)	7.70	5.53	5.53
Ind.11 ELOE (MWh/yr)	220.35	152.82	152.82

Table 10: Emissions from power generation

Pollutant	Scen.1	Scen.2	Scen.3	Scen.4	Scen.5	Scen.6
CO_2 (Mton/yr)	313.70	314.28	313.26	299.84	299.78	298.70
NO_x (kton/yr)	248.53	247.36	247.36	240.16	239.13	239.13
SO_x (kton/yr)	212.89	213.67	213.67	203.44	203.66	203.66

power plants. For the same reason, CO_2 emissions from power generation are also higher, when no price on allowances exists.

If environmental externalities of electricity production are not considered, the costs of the scenarios with and without fossil-fueled MGs are comparable; the difference, about 100 million euros, is due to the fact that more efficient technologies decrease the annual fuel consumption in the network when MGs are present. The costs of the scenarios including PV are instead about 500 million euros higher than the ones without MGs, and about 600 million euros higher than the ones including only fossil-fueled microgrids; the difference is due to much higher capital costs for the installation of PV systems and lead-acid battery banks. When externalities are considered, the gap between the costs of scenarios 1 and 4 (and 2 and 5) widens to approximately 200 million euros: in the non-MG scenarios costs are higher because they also include the external costs of heat production from the boilers. Comparing MG scenarios, while the ones including only fossil-fueled technologies have lower environmental costs, those including PV also account for the costs of the boilers needed to satisfy part of the heat load of the network; total environmental costs are therefore of similar magnitude.

The efficiencies of the MG scenarios (in particular total efficiencies) are higher than those of the other scenarios because of the increased amount of cogeneration. The introduction of even a moderate amount of MG capacity (8% of the generating capacity in the Netherlands) leads to an improvement by about 30% in the overall reliability of the Dutch system, as measured by the LOLP and ELOE. As mentioned previously, the estimate of reliability provided by the PV/fossil-fuel system may be optimistic.

It is difficult to assess the overall performance of the scenarios if each indicator is expressed in different units; this is the central challenge posed by multi-criteria decision problems. In line with [23], we normalize the values in Tables 8 and 9 after specifying a lower and upper threshold for each indicator. For the first five indicators the lower threshold is set equal to the lowest value among scenarios of the indicator, while the upper threshold is set equal to the highest value of the indicator. For the other indicators, a lower threshold of zero is chosen. Following [23], the upper threshold of η_e is set equal to 80% (the efficiency of a Carnot cycle operating between the environmental temperature of 298.15°K and an assumed temperature of 1486.7°K at the exit of the combustion chamber of the cogeneration system in the MG). Other efficiencies have an upper threshold of 1. For the LOLP the upper threshold corresponds to an outage of 24 hours/decade, while for the ELOE it is an expected loss of load of 1,000 MWh/yr. The values of the normalized indicators are shown in Table 11.

We calculate a sub-index for each group, obtained as the average of the indicators in the group. Each indicator is equally weighted. Finally, we aggregate our results in a composite sustainability index to gauge the overall performance of each scenario. The composite index is a simple average of the four sub-indices. If all sub-indices are given equal weights, a power network including fossil-fueled MGs and a price on CO_2 emission allowances achieves the highest sustainability, with a composite index of 0.792.

5.2. Sensitivity analysis 1: different weights

Our equal weighting may, of course, not be appropriate, depending on societal willingness-to-pay for emission reductions, cost reductions, efficiency improvements and reliability: for this reason we performed some sensitivity analyses. Results are given in Table 12. First, we assign more weight to each dimension (environmental, economic, technical and reliability) in turn. In all cases, Scenario 5 (fossil-fueled MGs and a price on CO_2 emission allowances) continues to represent the best alternative. However, the ranking of the other alternatives is different, depending on which dimension is given more or less weight.

5.3. Sensitivity analysis 2: social sustainability

To assess whether social sustainability considerations could change the outcome of the analysis, we have also performed a sensitivity analysis on the normalized values of the indicators. The goal is to assess how the introduction of a generic

Table 11: Normalized values of the indicators

Indicator	Scenario 1 No CO_2 No MG	Scenario 2 No CO_2 MG Fossil fuel mix	Scenario 3 No CO_2 MG Fossil + PV mix	Scenario 4 CO_2=25 €/ton No MG	Scenario 5 CO_2=25 €/ton MG Fossil fuel mix	Scenario 6 CO_2=25 €/ton MG Fossil + PV mix
Ind.1 CO_2	0.00	0.17	0.17	0.79	0.99	1.00
Ind.2 NO_x	0.00	0.35	0.36	0.63	0.99	1.00
Ind.3 SO_x	0.00	0.41	0.46	0.49	0.95	1.00
Environmental Subindex	**0.00**	**0.31**	**0.33**	**0.63**	**0.98**	**1.00**
Ind.4 Cost	0.86	1.00	0.22	0.67	0.80	0.00
Ind.5 Cost+Extern.	0.49	0.70	0.00	0.78	1.00	0.28
Economic Subindex	**0.68**	**0.85**	**0.11**	**0.72**	**0.90**	**0.14**
Ind.6 Eff.En.El.	0.5730	0.5728	0.5732	0.5759	0.5760	0.5764
Ind.7 Eff.En.Tot.	0.4595	0.4607	0.4606	0.4618	0.4633	0.4631
Ind.8 Eff.Ex.El.	0.4134	0.4133	0.4135	0.4155	0.4155	0.4158
Ind.9 Eff.Ex.Tot.	0.4580	0.4592	0.4590	0.4603	0.4617	0.4616
Technical Subindex	**0.4759**	**0.4765**	**0.4766**	**0.4784**	**0.4791**	**0.4792**
Ind.10 LOLP	0.68	0.77	0.77	0.68	0.77	0.77
Ind.11 ELOE	0.78	0.85	0.85	0.78	0.85	0.85
Reliability Subindex	**0.73**	**0.81**	**0.81**	**0.73**	**0.81**	**0.81**
Composite Subindex	**0.471**	**0.611**	**0.431**	**0.641**	**0.792**	**0.607**

social sustainability subindex might alter the results presented in our analysis. Table 12 shows the value that the social sustainability subindex would need to have, in order to achieve the same composite sustainability of the best alternative (0.792), if all criteria (environmental, economic, technical, social and reliability) were equally weighted. Even a terrible performance of the best scenario on the social sustainability indicator (i.e., a normalized value of its social indicator equal to zero) and an optimal performance of other scenarios (i.e., a normalized value of their social indicator equal to one) would not be enough to dislodge Scenario 5 from its top spot. Therefore, the inclusion of a social sustainability index would not significantly alter the conclusions of this paper.

5.4. *Sensitivity analysis 3: exclusion of external costs*

To account for the possibility that costs including externalities may duplicate other criteria (in particular, the environmental ones), we have calculated the values of the composite sustainability index disregarding Indicator 5; i.e., we only consider Indicator 4 in the economic sub-index. Table 12 presents the results. Even in this case, Scenario 5 (fossil-fueled MGs and a price on CO_2 emission allowances) achieves the highest composite sustainability index. The gap between the best and second-best alternatives remains similar, compared to the base case scenarios (Section 5.1); however, the ranking of the second and third best alternatives is inverted, with the scenario including MGs and no price on CO_2 performing better than the one without MGs and with a CO_2 price. On the contrary, the ranking of the three worst alternatives remains the same.

6. Conclusions

This paper assesses the sustainability and reliability of microgrids in the Northwestern European electricity market. Results suggest that a power network in which fossil-fueled microgrids and a price on CO_2 emissions are included achieves the highest composite sustainability.

From an environmental point of view, the scenarios including fossil-fueled MGs are more sustainable than the ones where no microgrids are present, because they yield a reduction in total pollutant emissions. However, some direct emissions from power generation may increase. If only a price on CO_2 emis-

Table 12: Values of the composite sustainability index
Sensitivity analyses

Sensitivity analysis	Dimension	Weight	Scenario 1 No CO_2 No MG	Scenario 2 No CO_2 MG Fossil fuel mix	Scenario 3 No CO_2 MG Fossil + PV mix	Scenario 4 CO_2=25 €/ton No MG	Scenario 5 CO_2=25 €/ton MG Fossil fuel mix	Scenario 6 CO_2=25 €/ton MG Fossil + PV mix
1	Environmental Others	70% 10%	0.188	0.431	0.369	0.637	0.903	0.843
1	Economic Other	70% 10%	0.595	0.755	0.238	0.690	0.857	0.328
1	Technical Other	70% 10%	0.474	0.530	0.458	0.544	0.604	0.530
1	Reliability Other	70% 10%	0.626	0.730	0.657	0.694	0.802	0.728
2	Social	20%	2.075	1.513	2.235	1.393	0.00	1.529
3	Indicator 5	0%	0.517	0.649	0.458	0.628	0.767	0.572

sion allowances was included, it would be possible to obtain higher emission reductions at a higher cost; all direct emissions from power generation would decrease. MGs including renewable technologies perform slightly better than the ones having a fossil-fueled generation mix, but the difference is not very significant in our simulations due to the small share assumed for PV.

From an economic point of view, MG scenarios may or may not be more sustainable than the ones excluding MGs, depending on the mix of generation technologies chosen in the microgrids. A large share of expensive technologies, such as fuel cells or photovoltaic, could make these scenarios less desirable than the alternative ones from an economic point of view.

MG scenarios are certainly more thermodynamically efficient because the same electric power and thermal load is satisfied using less energy and exergy. Thus, CHP in the MG produces both heat and power, while in the network electricity is provided by power plants and thermal energy by separate boilers. A comparison between fossil-fueled and fossil-fueled/PV MG scenarios reveals that, while the latter perform slightly better when only electric efficiencies are considered, the opposite is true when total efficiencies are taken into account, as PV does not contribute to heat generation and therefore part of the thermal load of the network has to be satisfied through electric boilers.

Finally, even with a moderate amount of microgrid capacity (8% of the total capacity in the Netherlands), the reliability (intended as long-run average availability) of the bulk power system is higher. Scenarios including MGs offer greater reliability because the generating capacity of a few, large natural gas CC and CT units in the non-MG scenarios is substituted with a great number of small generators with lower forced outage rates.

Several extensions of our regional assessment methodology are possible. For example, it would be useful to include a direct quantification of social sustainability, even though one of our sensitivity analyses showed this would not alter the main conclusions of the analysis. Another interesting addition would be the estimation of the external costs of pollutants for the regional grid accounting for specific, context dependent variables. As pointed out, both extensions would require making reference to specific locations and populations whose views and willingness to pay can be surveyed. Finally, it would be important to include other aspects of power reliability (in particular, customer outages arising at the distribution level) and power quality in the analysis.

Acknowledgements

Funding for this research was provided by the National Science Foundation under NSF-EFRI grant 0835879. The authors gratefully acknowledge useful comments by two anonymous referees. Opinions and errors are the responsibility of the authors.

Nomenclature

Indices of the optimization model

- i node in the network
- ik arc linking node i to node k
- j aggregate plant (step)
- m voltage loop

Indices of the reliability valuation model

- i node in the network
- j aggregate plant (step)
- w season of the year (winter/summer)
- z component of the MONA

Sets of the optimization model

I set of all nodes
J set of aggregate plants, differing in location, ownership, fuel type and cost
J_i set of aggregate plants at node i
M set of Kirchhoff's voltage loops
A_i set of nodes adjacent to node i
M_m ordered set of links ik in voltage loop m

Parameters of the optimization model

CO_2 CO_2 price, €/ton
L_i power demand at node i, MW
R_{ik} reactance on arc ik
S_{ikm} ± 1 depending on the orientation of arc ik in loop m
$Loss_{ik}$ resistance loss coefficient on arc ik, 1/MW
T_{ik} maximum transmission capacity on arc ik, MW
MC_{ij} marginal cost for generation at node i and step j, €/MWh
E_{ij} CO_2 emission rate at node i and step j, ton/MWh
Cap_{ij} maximum generation capacity at node i and step j, MW

Parameters of the reliability valuation model

Cap_{ij} maximum generation capacity at node i and step j, MW
FOR_{ij} forced outage rate for individual plants at node i and step j
N_{ij} number of individual power plants at node i and step j
L_z power demand of the z^{th} component of the MONA, MW
Cap_w expected generating capacity in season w, MW
$Wind_w$ wind generation in season w, MW
λ_w parameter of the exponential approximation to wind distribution in season w, MW

Decision variables of the optimization model

f_{ik} export flow from node i to node k, MW
gen_{ij} generation at node i by aggregate plant j, MW

Decision variables of the reliability valuation model

μ_z mean of the z^{th} component of the MONA, MW
σ_z^2 variance of the z^{th} component of the MONA, $(MW)^2$
p_z weight of the z^{th} component of the MONA

Thermodynamic variables

$\dot{W}$ annual electric power load of the network, MWh
$\dot{Q}$ annual heat load of the network, MWht
η_b efficiency of the boilers
η_e annual energetic electric efficiency of the network
η_{tot} annual energetic total efficiency of the network
ζ_e annual exergetic electric efficiency of the network
ζ_{tot} annual exergetic total efficiency of the network
φ_e exergy to energy ratio of fuels used for electricity generation in the network
$\dot{E}_S^Q$ exergy content of the heat load, MWh
$\dot{E}_{NG}$ exergy flow rate of natural gas, MJ/s*hour
$\dot{M}_{NG}$ mass flow rate of natural gas, kg/s
H_{NG} Lower Heating Value of natural gas, MJ/kg
φ_{NG} exergy to energy ratio of natural gas

References

[1] Market integration: coupling of the European electricity markets [Internet]. Available from: http://www.tennettso.de/pages/tennettso_en/Press/Information_Material/PDF/100478_TEN_Brochure_marktkoppeling.pdf [accessed 2011 Jun 24].
[2] CWE Market integration [Internet]. Available from: http://www.apxendex.com/index.php?id=186 [accessed 2011 Jun 24].
[3] Report of the United Nations World Commission on Environment and Development. Our common future [Internet]. Available from: http://www.un-documents.net/wced-ocf.htm [accessed 2011 Jun 24].
[4] Hobbs, B.F., Meier, P. Energy decisions and the environment: a guide to the use of multicriteria methods. Kluwer Academic Publishers; 2000.
[5] Lebre LaRovere, E., Borghetti Soares, J., Basto Oliveira, L., Lauria, T. Sustainable expansion of electricity sector: sustainability indicators as an instrument to support decision making. Renewable and Sustainable Energy Reviews 2010; 14: 422-9.
[6] Giannantoni, C., Lazzaretto, A., Macor, A., Mirandola, A., Stoppato, A., Tonon, S. et al. Multicriteria approach for the improvement of energy systems design. Energy 2005; 30(10): 1989-2016.
[7] Wang, J., Jing, Y., Zhang, C., Zhao, J. Review on multi-criteria decision analysis aid in sustainable energy decision making. Renewable and Sustainable Energy Reviews 2009; 13: 2263-2278.
[8] Maruyama, Y., Nishikido, M., Iida, T. The rise of community wind power in Japan: enhanced acceptance through social innovation. Energy Policy 2007; 35(5): 2761-2769.
[9] Gallego Carrera, D., Mack, A. Sustainability assessment of energy technologies via social indicators: results of a survey among European energy experts. Energy Policy 2010; 38: 1030-1039.
[10] Turvey, R., Anderson, D. Electricity economics: essays and case studies. Baltimore: Johns Hopkins University Press; 1977.
[11] ExternE: externalities of energy, Vol.1; 1995 [Internet]. Available from: http://www.externe.info/ [accessed 2011 Jun 24]
[12] Ottinger, R.L., Wooley, D., Robinson, N., Hodas, D., Babb, S. Environmental costs of electricity. New York: Oceana Publications; 1990.
[13] Hohmeyer, O., and Ottinger, R.L., editors. External environmental costs of electric power: analysis and internalization. Proceedings of a German-American Workshop; 1990, October 23-25; Ladenburg, FRG. New York: Springer-Verlag; 1991.
[14] Gil, H.A. Models for quantifying the economic benefits of distributed generation. IEEE Transactions on Power Systems 2008; 23(2): 327-35.
[15] Tsikalakis, A.G., Hatziargyriou, N.D. Environmental benefits of distributed generation with and without emissions trading. Energy Policy 2007; 35(6): 3395-409.
[16] Hadley, S.W., Van Dyke, J.W., Poore III, W.P., Stovall, T.K. Quantitative assessment of distributed energy resource benefits [Internet]. Oak Ridge National Laboratory, Engineering Science and Technology Division. Available from: http://www.ornl.gov/∼webworks/cppr/y2001/rpt/116227.pdf. [accessed 2011 Jun 24].
[17] U.S. Department of Energy. The potential benefits of distributed generation and rate-related issues that may impede their expansion [Internet]. Available from: http://www.ferc.gov/legal/fed-sta/exp-study.pdf. [accessed 2011 Jun 24]
[18] Alanne, K., Sari, A. Distributed energy generation and sustainable development. Renewable and sustainable energy reviews 2006; 10(6): 539-58.
[19] Firestone, R., Marnay, C., Maribu, K.M. The value of distributed generation under different tariff structures. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2006 May. Report No.: LBNL-60589. Contract No.: DEAC0205CH11231. Sponsored by the US Department of Energy.
[20] Siddiqui, A.S., Marnay, C., Edwards, J.L., Firestone, R., Ghosh, S., Stadler, M. Effects of a carbon tax on microgrid combined heat and power adoption. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2004 Oct. Report No.: LBNL-51771. Contract No.: DEAC0376SF00098. Sponsored by the US Department of Energy.
[21] Marnay, C., Lai, J., Stadler, M., Siddiqui, A. Added value of reliability to a microgrid: simulations of three California buildings. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Tech-

nologies Division; 2009 Apr. Report No.: LBNL-1853E. Contract No.: DEAC0205H11231. Sponsored by the US Department of Energy.

[22] Yi, H., Hau, J.L., Ukidwe, N.U., Bakshi, B.R. Hierarchical thermodynamic metrics for evaluating the environmental sustainability of industrial processes. Environmental Progress 2004; 23(4): 302-14.

[23] Frangopoulos, C.A., Keramioti, D.E. Multi-criteria evaluation of energy systems with sustainability considerations. Entropy 2010; 12(5): 1006-20.

[24] Frangopoulos, C.A., von Spakovksy, M.R. A global environomic approach for energy systems analysis and optimization. Proceedings of the Energy Systems and Ecology Conference; 1993 July 5-9; Cracow, Poland. p.123-44.

[25] von Spakovksy, M.R., Frangopoulos, C.A. The environomic analysis and optimization of a gas turbine cycle with cogeneration. American Society of Mechanical Engineers (ASME) 1994; 33: 15-26.

[26] Rosen, M. Energy and exergy-based comparison of coal-fired and nuclear steam power plants. Exergy 2001; 1(3): 180-92.

[27] Zvolinschi, A., Kjelstrup, S., Bolland, O., van der Kooi, H.J. Exergy sustainability indicators as a tool in industrial ecology. Journal of Industrial Ecology 2007; 11(4): 85-98.

[28] Billinton, R., Allan, R.N. Reliability evaluation of power systems: concepts and techniques. New York: Plenum Press; 1996.

[29] Stoll, H.G. Least-cost electric utility planning. New York: John Wiley and Sons; 1989.

[30] Wood, A.J., Wollenberg. B.F. Power generation operation and control. New York: John Wiley and Sons; 1996.

[31] Marnay, C. Microgrids and heterogenous power quality and reliability. Berkeley (CA): Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division; 2008 Jul. Report No.: LBNL-777E. Contract No.: DEAC0205CH11231. Sponsored by the US Department of Energy.

[32] Chowdhury, S., Chowdhury, S.P., Crossley, P. Microgrids and active distribution networks. London: The Institution of Engineering and Technology; 2009.

[33] Council of European Energy Regulators. Fourth benchmarking report on quality of electricity supply 2008 [Internet]. Available from: http://www.autorita.energia.it/allegati/pubblicazioni/C08-EQS-24-04_4th_Benchmarking_Report_EQS_10-Dec-2008_re.pdf [accessed 2011 Jun 24].

[34] Hobbs, B.F. Models for integrated resource planning by electric utilities. European Journal of Operational Research. 1995; 83(1): 1-20.

[35] Hobbs, B.F., Rijkers, F.A.M. Modeling strategic generator behavior with conjectured transmission price responses in a mixed transmission pricing system I: formulation, IEEE Transactions on Power Systems 2004; 19(2): 707-17.

[36] Hobbs, B.F., Drayton, G., Bartholomew Fisher, E., Lise, W. Improved transmission representations in oligopolistic market models: quadratic losses, phase shifters, and DC lines. IEEE Transactions on Power Systems 2008; 23(3): 1018-29.

[37] Energy Research Centre of the Netherlands. COMPETES input data [Internet]. Available from: http://www.ecn.nl/fileadmin/ecn/units/bs/COMPETES/cost-functions.xls [accessed 2011 Jun 24]

[38] International Energy Agency. Energy Prices and Taxes, energy end-use prices in national currencies, vol.2. Paris: International Energy Agency; 2010.

[39] International Energy Agency. Electricity Information. Paris: International Energy Agency; 2010.

[40] European Network of Transmission System Operators for Electricity. Hourly load values for a specific country for a specific month [Internet]. Available from: https://www.entsoe.eu/index.php?id=137 [accessed 2011 Jun 24].

[41] International Energy Agency Energy Conservation in Buildings and Community Systems, Annex 42 [Internet]. Standard European Electrical Profiles. 2006. Available from: http://www.ecbcs.org/docs/Annex_42_European_Electrical_Standard_Profiles_Annex_42_September_2006.zip [accessed 2011 Jun 24].

[42] De Vries, L.J. Generation adequacy: helping the market do its job. Utilities Policy 2007; 15(1): 20-35.

[43] Gross, G., Garapic, N.V., McNutt, B. The mixture of normals approximation technique for equivalent load duration curves. IEEE Transactions on Power Systems 1988; 3(2): 368-74.

[44] North American Electric Reliability Corporation. 2005-2009 Generating Availability Report [Internet]. Available from: http://www.nerc.com/page.php?cid=4|43|47 [accessed 2011 Jun 24].

[45] Energy and Environmental Analysis, Inc. Distributed generation operational reliability and availability database. Executive summary report [Internet]. Available from: http://files.harc.edu/Sites/GulfCoastCHP/Publications/Distributed OperationalReliability.pdf [accessed 2011 Jun 24].

[46] Hargreaves, J.J., Hobbs, B.F. Optimal commitment and dispatch with uncertain wind generation using stochastic dynamic programming. Manuscript, Department of Geography & Environmental Engineering, Johns Hopkins University, 2010.

[47] AEA Technology. Environmental Product Declaration of Electricity from Torness Nuclear Power Station - a technical report [Internet]. Available from: http://www.british-energy.com/documents/EPD_Doc_-_Final.pdf [accessed 2011 Jun 28].

[48] Spath, P.L., Mann, M.K., Kerr, D.R. Life cycle assessment of coal fired power production. Golden (CO): National Renewable Energy Laboratory; 1999 June.

[49] Spath, P.L., Mann, M.K. Life cycle assessment of a natural gas combined-cycle power generation system. Golden (CO): National Renewable Energy Laboratory; 2000 September.

[50] Kaewboonsong, W., Kuprianov, V.I., Chovichien, N. Minimizing fuel and environmental costs for a variable-load power plant (co-)firing fuel oil and natural gas. Part 1. Modeling of gaseous emissions from boiler units. Fuel processing technology 2006; 87: 10851094.

[51] Boudghene Stambouli, A., Traversa, E. Solid oxide fuel cells (SOFCs): a review of an environmentally clean and efficient source of energy. Renewable and Sustainable Energy Reviews 2002; 6: 433-455.

[52] Greenhouse Gas Technology Center - Southern Research Institute. Environmental technology verification report. Combined heat and power at a commercial supermarket - Capstone 60 kW microturbine CHP system [Internet]. Available from: http://www.capstoneturbine.com/_docs/EPA-C60testreport.pdf [accessed 2011 Jun 27].

[53] Pipattanasomporn, M., Willingham, M. White paper on distributed generation [Internet]. Available from: http://www.idc-online.com/technical_references/pdfs/electrical_engineering/Distributed %20generation.pdf [accessed 2011 Jun 27].

[54] EcoSenseWeb [Internet]. Available from: http://ecosenseweb.ier.uni-stuttgart.de/.

[55] NEEDS - New Energy Externalities Developments for Sustainability. Report on the procedure and data to generate averaged/aggregate data, RS3a-D1.1; 2008 [Internet]. Available from: http://www.needs-project.org/2009/ [accessed 2011 Jun 24].

[56] Bejan, A., Tsatsaronis, G., Moran, M. Thermal design and optimization. New York: John Wiley and Sons; 1996.