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Applying Time Series to Power Flow Analysis in Networks with High Wind Penetration

Thomas Boehme, A. Robin Wallace, and Gareth P. Harrison

***Abstract*—With high levels of variable renewable generation in distribution or transmission systems the application of demand and generation time series to power flow analyses can be advantageous. Demand data is often available from historic measurements while renewable generation such as wind turbine output may be recorded or can be derived from resource measurements over the corresponding period of time. Power flow solutions with hourly time steps over a year or more can then be used to produce load duration curves for system components. This paper shows, by example, how utilities can use the method to determine overload conditions or to specify non-firm connection agreements for new generators.**

***Index Terms*—Load duration curve, power flow analysis, time series, variable generation, wind power.**

I. Steady-state Power Flow Analysis

POWER flow analysis is an integral part of system planning and operation. The electrical system is modelled by buses with generators and loads which are interconnected by branches and transformers. The *steady-state solution* of the network determines the bus voltages from which the active and reactive power flow in branches can be calculated [1].

Fig. 1 shows a general network with two distributed generators DG1 and DG2, and a load. Active power and control voltage are directly specified for DG1 (PV bus), active and reactive power are given for DG2 and the load (PQ buses), while the swing bus generator will balance power in the system [2]. The network solution determines the power flowing in the branch of interest, here depicted as a transformer.

The power system behaviour is often studied taking account of seasonal loading of branches (e.g. at winter peak demand) under specific network conditions including loss of generation, circuit outages, and network upgrades. The loads at each bus are set to representative values derived from minimum, typical and peak conditions, as shown in Fig. 2a. The assumption that demand is known holds for historic and real time analysis while forecast estimates have to be used for any future scenario. To meet load demand, the generation portfolio must be adequate. National power systems have evolved over decades and some form of central dispatching was used. The dispatch of plant is influenced, for instance, by the security of fuel supply, scheduled maintenance periods and reliability. With the liberalisation of power systems the dispatch is primarily governed by market prices that influence the availability and operation of power plants in a given hour. With some years of experience it is still possible to roughly determine which large power plants are likely to provide base load, intermediate load and peak load and to construct representative power flow cases. When large-scale hydro is present, the seasonal availability of water must also be taken into account. In addition to these conventional forms of generation there are an increasing number of new, renewable generators connected to the electricity network. A 'wind penetration' of 10% to 20%, understood as the ratio of actual wind power production to actual demand, will in many systems have an appreciable effect [3]. With such high levels of variable renewable generation from wind a single power flow solution can no longer describe the possible system states in a representative way.

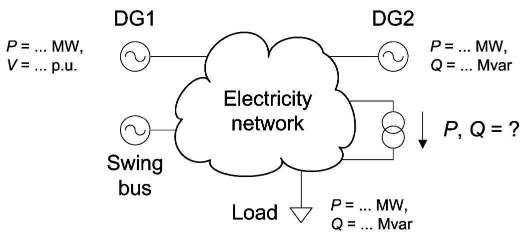

Fig. 1. Typical steady-state power flow problem.

II. Power Flow with Variable Load and Generation

Generally a power system is operated so that the generation portfolio satisfies the load demand through the use of the transmission and distribution network. The loads vary and their statistical distributions and the correlation between them must be modelled. *Stochastic (or probabilistic) power flow* analyses can be divided into direct and Monte Carlo simulations. In the former an initial solution is based on the mean (expected) loads and (where applicable) generators' output. The power flow equations are then often linearised

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around this starting point. In the past, models for the correlation between loads have assumed independence, linear dependence or more sophisticated relationships [4]. A comprehensive literature review can be found in [5]. More recently, methods have been extended to include quadratised power flow AC analysis [6]. Monte Carlo analysis refers to multiple deterministic power flow solutions which incorporate the nonlinearities of the system. Random samples of parameters are chosen based on their probability density functions. A large number of simulations (e.g. 20,000) are required to determine the statistical distribution of voltages and currents. Fuzzy arithmetic [7] has been suggested for cases where loads or generators do not have a random nature or where incomplete or qualitative information has to be used. Then system optimal (while uncertain) operation can be determined using linear programming techniques. Interval arithmetic [8] takes the uncertainty of nodal information into account and provides bounds of the solution. Since all possible solutions are included, the results may appear very conservative.

Due to the historically small contribution which wind power has made in large power systems, the methods described above were mainly concerned with variable loads and dispatchable generation. Long-term statistical data as illustrated by Fig. 2 for both demand and onshore wind turbine output (in Scotland, and generally applicable in north-western Europe) shows some similarities in behaviour: Demand and generation in winter are higher than in summer and around midday they are higher than at midnight. Despite this resemblance it is possible that the combined wind farm output across an area as large as Scotland will be well below 10% of rated capacity while demand is above 90% of the annual peak [9]. This explains the difficulty in defining a typical base case operating point for probabilistic power flow or sensitivity analysis.

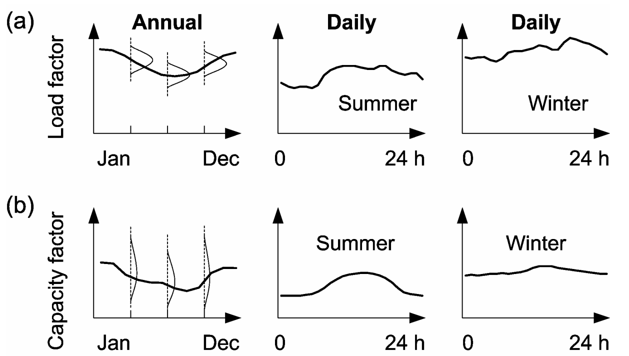

Fig. 2. Typical (a) load and (b) wind turbine output profiles. Data drawn from demand metering by the Scottish utilities and wind measurements across Scotland [9]. Annual profiles include probability distributions.

Fig. 3 illustrates this further for a wind farm. The wind speed at the site is described by a Weibull distribution [10] with a shape parameter k = 2.0 and a scale parameter c = 8.0 m/s indicated by the probability density function $p(v)$. The average wind speed v_{avg} is then 7.1 m/s, the modal value, i.e., the most frequent wind speed v_{mod} is 5.7 m/s and the wind speed v_{pp} where the highest power density occurs is 11.3 m/s. Using the power curve of a 2.5 MW wind turbine [11] having a cut-in wind speed $v_{cut\text{-}in}$ of 3.5 m/s, a cut-out wind speed $v_{cut\text{-}out}$ of 25.0 m/s and a nominal (rated) wind speed v_{nom} of 14.5 m/s the annual energy output E can be calculated.

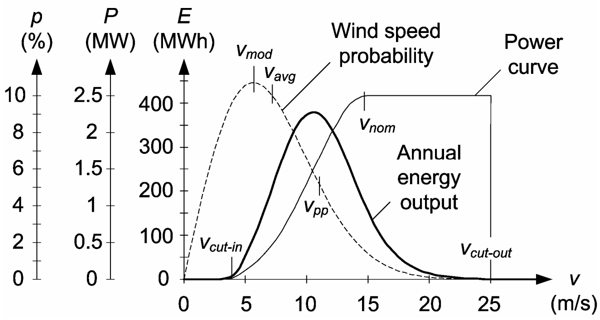

Fig. 3. Wind speed and turbine characteristics. Weibull distribution with k = 2.0 and c = 8.0 m/s. 2.5 MW turbine, adapted from a Nordex N80 [11].

The key issue is which wind speed and corresponding power output should be used for a representative power flow simulation. Taking modal or average wind speed will result in a very low power output. This could be partly overcome by using seasonal wind speed distributions. Then, for north-western Europe, the average 'winter' wind speed would be higher than the annual value and be more applicable for a 'winter peak demand' power flow case. This can give appropriate results with single wind farms. However, for a geographically extensive, meshed system with a high number of wind farms such estimations will not produce useful information.

The solution proposed here is to apply a large number of possible scenarios in power flow analysis. Unlike for the Monte Carlo method the input data is not derived from statistical distributions but the *time series* of demand and generation are directly applied. Such methods have been successfully used to determine the impact of wind turbines on the steady state operation of radial distribution networks [12] and to obtain agreement for connection of a wind farm in Scotland [13]. The management of these network constraints is a challenging issue which has been the subject of much debate in Scotland [14].

III. Application of Time Series

The application of time series is illustrated in Fig. 4. The single power flow problem with mean values is expanded to multiple simulations with individual values for each time step. Using recorded data of stochastic load and generation, many vectors have to be used to obtain generally applicable results. With the variation of wind and demand over the year it is reasonable to cover at least one year. Due to the daily profile of demand and the variability of wind over a day a time step of one hour or less is suggested. This means that at least 8,760 power flow simulations need to be solved.

With proper demand profiles and (historic) wind power records applied to the network model for each hour, it is then possible to derive a variety of results from these multiple solutions. This proposed, rigorous method has two distinct features: (1) The time series of any electrical quantity can be evaluated and compared to other quantities of interest with time steps that need more careful investigation being re-simulated and checked within the power flow analysis software; (2) The recorded information can be evaluated with statistical methods and, for instance, be presented in the form of load duration curves which are commonly used for power system characterisation.

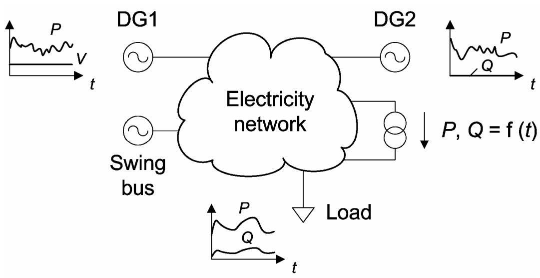

Fig. 4. Time series applied to the power flow problem.

Power utilities generally have archived records of demand metering at supply points with 15 minute, half-hourly or hourly periods. After the removal of errors and corrupt data and the patching of gaps they can form the load vectors for the analysis. Application of measured records has the advantage that the correlation between individual loads does not have to be explicitly known.

This benefit applies even more to wind generation, as single wind time series can be easily created [15, 16], but correlation between farms is hard to model [4]. The wind turbines' output can be based on records from wind farms in the area or it has to be derived from wind data. In many countries there is a network of synoptic meteorological stations which record wind data on an hourly basis. In the U.K. such recordings are made by the Met Office, generally 10 m above ground level. Alternatively there may be wind measurement masts installed for wind resource screening. A further source of data can be the output of climate models. Depending on the distance between measurement points and wind farms some interpolation may be needed. Using the microscale modelling software WAsP [10], the wind resource can be calculated in the wind farm areas. Time series of wind speed can then be calculated at the wind projects based on speed-up factors, i.e. the ratio of average wind speeds at the site of interest (at hub height) and measurement or simulation (often at 10 m above ground level), individually for a number of directional sectors (usually 12 or 16). Using the measured (or simulated) time series it is then possible to create wind speed time series for nearby sites. Based on the power curves of turbines to be used, hourly power output can thereafter be calculated for each wind farm. When projects spread out over large areas, it is sensible to calculate wind speeds for sub-areas in order to achieve a 'park effect' in the modelling. Then, for example, not all machines would cut out at the same time should the wind speed reach or exceed 25 m/s. When large areas are to be covered, data from several measurement points should be used and the calculated time series have to be interpolated, e.g. with an inverse distance weighting. In the following section this method is illustrated by an example.

IV. Outer Hebrides Case Study

The northern part of the Outer Hebrides (also known as the Western Isles), a group of islands in north-western Scotland, United Kingdom, was selected for a case study. The area studied in detail included the islands of Lewis and Harris (Fig. 5) which have widely been considered for large-scale development of onshore wind projects.

At present these islands are connected through a 33 kV subsea cable to the Scottish transmission network on the island of Skye (extending from there to the Scottish mainland). The distribution on Lewis and Harris is carried out at 33 kV and 11 kV. A direct 132 kV line transmits power between Harris and Stornoway (Fig. 6), running in parallel to existing 33 kV circuits (now normally open). The transmission line is very lightly loaded and the anticipated area demand growth of about 1% per annum in the populated area around Stornoway [17] will have little impact. Renewable energy developments in combination with subsea cable reinforcements could however change this. Currently the generation capabilities on the islands include only small-scale hydro and diesel.

A. Power System Modelling

The aggregated minimum demand on Lewis and Harris in summer is between 6 and 7 MW [17]. The demand profile was derived from the transmission network owner's measurement records for northern Scotland. Fig. 7 shows a simplified distribution network model as used by the distribution network owner [17]. The values shown are for a winter 2004/05 case. The total demand on Lewis and Harris amounts to 24.7 MW for this particular scenario. Some of this high demand is satisfied from the diesel generators at Battery Point, a small amount is contributed from two hydro installations and the rest is supplied via the subsea cable. The utility has also modelled the first consented wind farm at Arnish Moor which will consist of 3×1.3 MW stall regulated wind turbines. A rather high output of 3.0 MW was chosen by the utility to represent the wind farm's output for this case. Since both the diesel generators and the subsea cable still have sufficient margin to supply power, the validity of the results is not compromised.

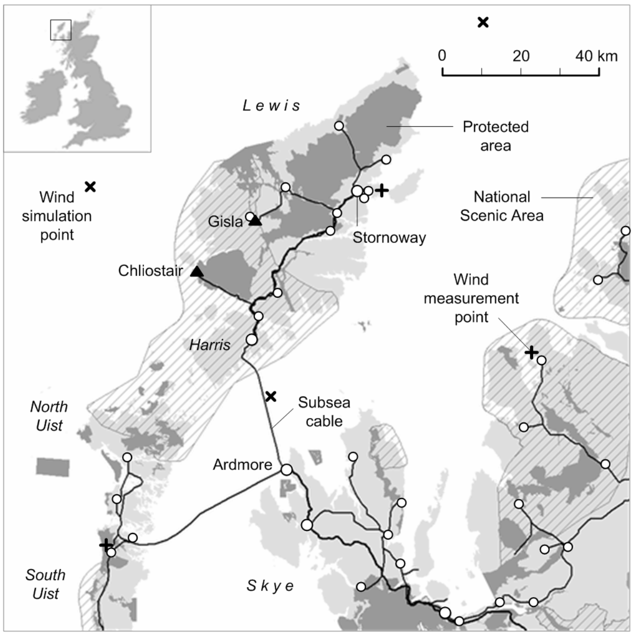

Fig. 5. Distribution network on the Outer Hebrides, Scotland, U.K.

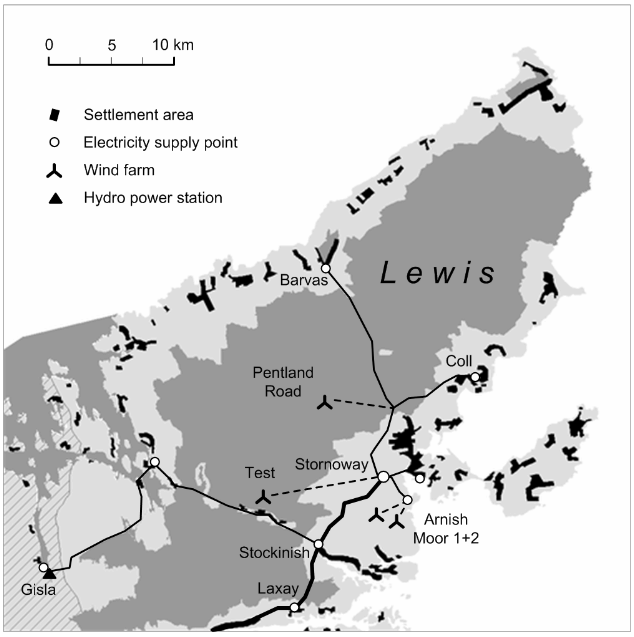

Fig. 6. Wind farm connections on Lewis.

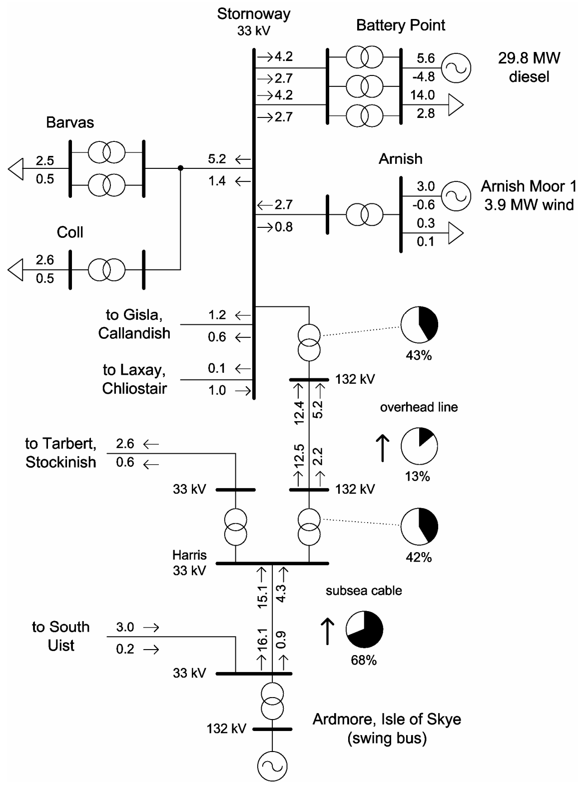

Fig. 7. 33 kV distribution network in the Outer Hebrides (partly shown). High winter demand period [17]. Numbers above or to the left of the branch indicate active power in MW, numbers below the branch or to its right indicate reactive power in Mvar.

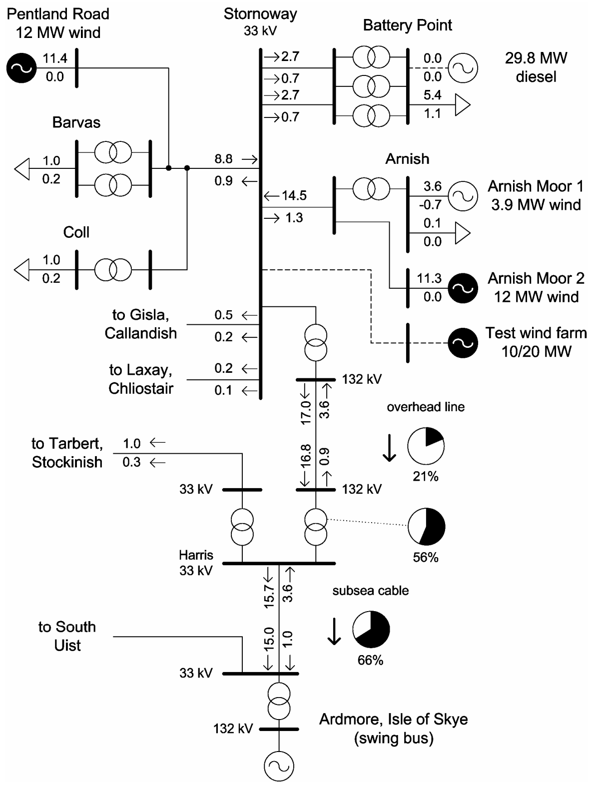

Fig. 8. 33 kV distribution network with new generation connected. Low summer demand with high wind generation (Friday, 20 June 2003, 03:00 h).

Besides the planned wind farm at Arnish Moor, there are two more consented projects, Arnish Moor 2 and Pentland Road, which will have capacities of 12 MW each. These have been connected to the distribution network model as shown in Fig. 8. For sensitivity analysis a further 'Test' farm with variable capacity was connected in this study. The snapshot shown in Fig. 8 is for 20 June 2003, 03:00 h, an hour of low summer demand [18] with particularly high wind turbine output, assuming that the wind projects had been installed at that time.

The wind turbines' output was based on wind data records from three onshore meteorological stations in the area (Stornoway, South Uist, and Aultbea; see Fig. 5) and three offshore simulation points of the 'UK Waters Wave Model' [19] operated by the U.K. Met Office which, among others, simulates wind speeds at 10 m above sea level. Applying these six records in the WAsP modelling package, the wind resource and time series were calculated across the wind farm areas six times. The time series were then averaged with an inverse distance weighting, i.e., the measurement near Stornoway had the biggest impact due to its proximity to the wind farms. The power curves of the turbines in each wind farm were then applied to calculate turbine output. The algorithm to calculate turbine power output also approximated (on an hourly basis) the high-wind cut-out at 25 m/s and the subsequent cut-in at lower wind speed (taken to be 22 m/s).

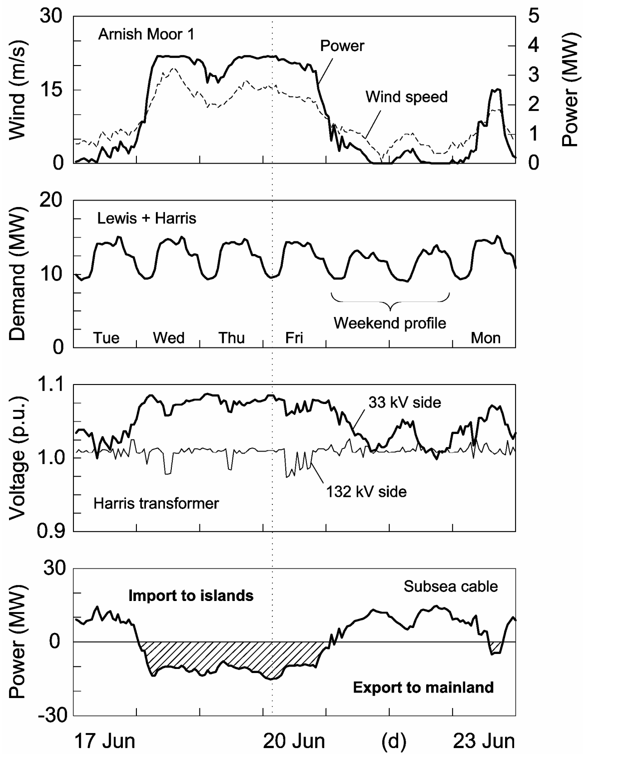

Fig. 9. Example time series for "Consented wind" scenario from 17 June 2003 (Tuesday) through 23 June 2003 (Monday) for Arnish Moor 1 wind speed and power output, Lewis and Harris demand, voltages at a Harris 132 kV/33 kV transformer and corresponding subsea cable active power flow. The dotted line is for 20 June 2003, 03:00 h, as in Fig. 8.

Hourly time series over a period of three years from 01 January 2001, 01:00 h through 31 December 2003, 24:00 h were created for all four wind farms. Wind farm and hydro output together with demand were then applied to power flow simulations for each time step of one hour (i.e. a total of 26,280 time steps). The results were saved and analysed. As an example, Fig. 9 shows a week of time series for several points of interest with the consented wind farms connected to the system. The time was chosen so that the hour displayed in Fig. 8 is included (indicated by the vertical dotted line). Wind speed and power vary considerably throughout the seven days, the latter from zero to rated power. The demand during the weekdays exhibits a different profile than during the weekend. The voltages of the 132 kV/33 kV transformer at the end of the subsea cable in Harris shows significant deviations from 1.0 p.u. This is due to the larger regulation range allowed for this unit and the way automatic tap changing is implemented in the power flow software. Finally, the active power flow in the subsea cable is depicted. When the wind blows stongly, the islands export power to the Scottish mainland, as indicated by the hatched area.

B. Simulation Results

Due to the low local demand and a relatively high capacity 132 kV line across the island, the limiting factor for wind energy exploitation in the area is the subsea cable. Fig. 10 shows the voltage V_2 at the receiving (load) end of the cable when a voltage V_1 = 1.0 p.u. $\angle$ 0° is applied at the sending (generator) end. Depending on the network impedance at the receiving end the amount of power that can be transmitted will be more or less limited. Transformers with on-load tap changers at both sides of the cable ensure that active power exceeding 20 MW can generally be transmitted.

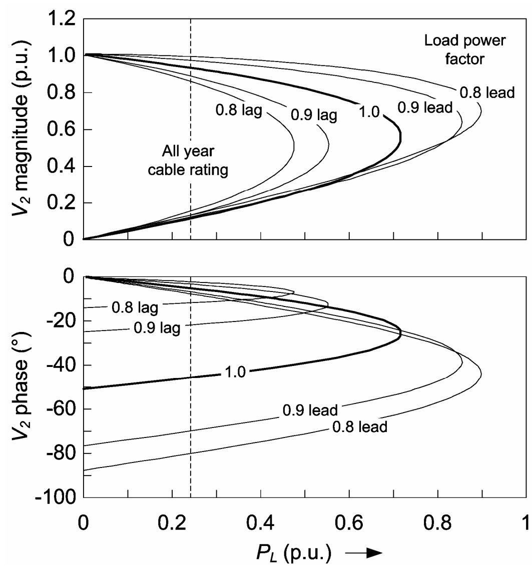

Fig. 10. 23.4 MVA subsea cable transfer characteristics. Length 33 km. Load expressed in per unit (p.u.) on a 100 MVA basis.

Fig. 11a shows the obtained subsea cable load duration curves for a few scenarios. The 68% cable loading shown in Fig. 7 is a good average value for the case with just 3.9 MW of wind installed (for which the curve would lie just below the “No wind” trace). This single, seasonal value masks, however, important information. With no wind turbines installed, the cable is lightly overloaded for about 2% of the year (Fig. 11b). With around 40 MW (‘Consented wind + 10 MW’) of wind capacity the overloading conditions become less frequent and less severe. The case ‘Consented wind + 20 MW’ was used to explore the limits of the distribution system. It can be seen that such a capacity of wind power would be well beyond the capability of the system. As such, not much more than 10 MW in addition to the consented projects should be planned to avoid frequent overloading. When the thermal properties of the cable (or more generally a branch) are known, the effect of the overloading conditions can be further investigated in the time domain. This would indicate whether critical temperatures are exceeded and if so, by what value and duration.

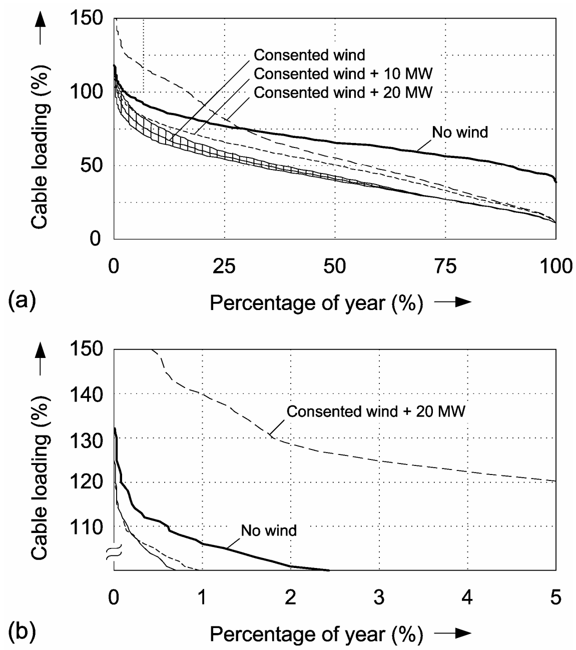

Fig. 11. 23.4 MVA subsea cable loading for different scenarios. (a) Complete curve, the ‘Consented wind’ curve contains a band for the year-to-year variation; (b) Enlargement for extreme loading.

While branch overloading was allowed in the simulations, voltage levels were maintained using automatic tap changers. The normal voltage range in the 11 and 33 kV network is ± 6%, but up to ± 10% were allowed at the subsea cable ends. The voltage levels and tap positions can be recorded throughout the simulation. For a statistical analysis, however, a time step of 10 or 15 minutes would be more meaningful in order to properly address fluctuations of wind power generation and load. Detailed long-term measurement data would be a pre-requisite for such an analysis. Simulations with tap changing disabled were also run but showed that statutory voltage limits would be violated many times and that the installable wind capacity would only be a fraction of that already consented. Furthermore, the simulations would not converge for a significant number of time steps. In areas where there are no tap changers or where the adjustment range is insufficient, the prospects of installing distributed generators may be very limited.

The year-to-year variation is shown in Fig. 11a for the ‘Consented wind’ case for which the range of results for individual years is indicated by the hatched area. The spread of the band indicates that it would be desirable to explore even longer time series than three years.

Fig. 12 shows that, with no wind turbines installed, the islands are an importer of electricity at all times. This will still be true when the first wind farm with 3.9 MW capacity becomes operational. With the consented wind projects amounting to 27.9 MW, the islands will export electricity to the mainland for more than 30% of the time. With an additional installation of 10 MW, this time would increase beyond 40%. Like in the previous figure the year-to-year variation is indicated for the ‘Consented wind’ case by a hatched range.

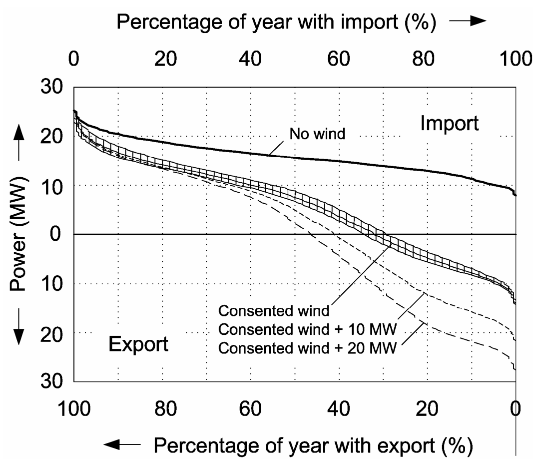

Fig. 12. Lewis import and export for different wind development scenarios. The ‘Consented wind’ curve contains a band for the year-to-year variation.

Given that the subsea cable is a critical element of this system, it was an obvious element to investigate, but equally data can be extracted and analysed for any system component of interest. Fig. 13 shows a load duration curve for the 132 kV/33 kV transformer at the end of the subsea cable in Harris. It can be seen that its loading is rather light and it will be further decreased when all the consented wind farms are installed. Only in the case of the 20 MW ‘Test’ farm in addition to the consented wind farms would the transformer experience overloading. The simulation results show that this may happen for 3% of the year.

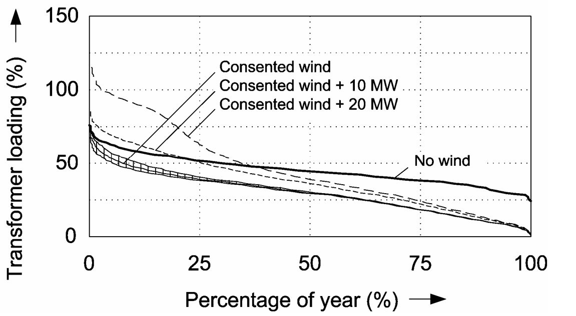

Fig. 13. Harris 132 kV/33 kV, 30 MVA transformer loading for different scenarios. The 'Consented wind' curve contains a band for the year-to-year variation.

The simulations described were carried out with an intact network under normal operating conditions. It would also be possible to model outages of single or multiple circuits. Failures of either the subsea cable or the 132 kV transmission line (N-1 contingency) would have the most severe impact in the system described. In both cases the diesel generator at Stornoway would have to be brought online to supply the islanded area. At current load levels this would be possible even if the wind turbines made no contribution at all. In addition, network upgrades could significantly alter the results of this study. There are proposals to install a wind farm with more than 500 MW capacity on the island of Lewis [20] which would require a new subsea connection between the Outer Hebrides and the Scottish mainland [21].

C. *Further Applications*

Fig. 14a shows the annual performance of the four modelled wind farms. The difference in output stems mainly from the different site elevations and hub heights. In the model, the turbines never reach rated power due to a global reduction of 5%, representing the combined downtime, electrical and wake losses, which were applied across the year.

Voltages have been assessed under steady-state conditions and are in practice dependent on the control of reactive power in the wind farms. As long as the tap changers at both ends of the subsea cable are able to cope with the voltage variation, the three consented projects might be offered firm connection to the network. The analysis puts the utility in a position to give the 'Test' wind farm practically 'firm' connection if its capacity does not exceed 10 MW. With 20 MW its output would have to be constrained at many hours of the year just to avoid voltage collapse. Detailed wind turbine data would, however, be needed for a subsequent transient analysis of which the results may, depending on the particular turbine type, further limit the number installable machines. Such an analysis was beyond the scope of this paper.

The output reduction, i.e. the constraining of wind farm production by the network operator, was performed during the power flow simulations by reducing the test farm's generation in 5% steps until a solution could be found. This results in the visible steps in Fig. 14b, in a small reduction of the plant capacity factor from 36.8% to 36.2% and in an associated loss of revenues for this hypothetical farm. Fig. 11 showed that this reduction would be insufficient to prevent the heavy overloading of the subsea cable. Further simulations would be required to determine the acceptable capacity of the 'Test' wind farm.

A probabilistic analysis can give similar results provided that correlation is appropriately modelled. Direct application of time series obtained for the area of interest is more straightforward from a utility's point of view. Provided that a representative period of time is covered, i.e. generally one to several years, the overall result will describe the system behaviour well. Moreover, each single time step will be meaningful to the utility and detailed analyses for specific time windows can be carried out.

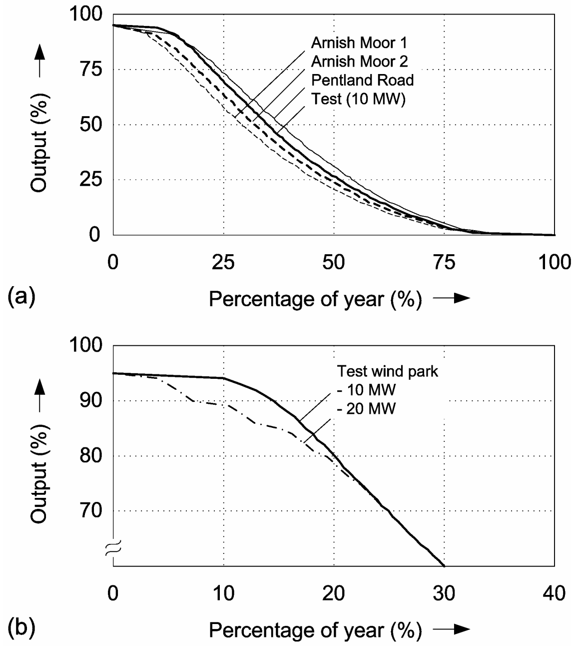

Fig. 14. Wind farm annual performance. (a) Consented farms and 10 MW test farm. (b) Test farm with 10 MW and 20 MW capacity, 5% output reductions by distribution network operator visible in the 20 MW case.

V. Conclusions

Power systems have traditionally been analysed by considering typical winter and summer cases for which power flow simulations produce discrete values for nodal voltages and branch power flows. Highly variable generation such as wind power is not realistically characterised by a single value of power output, in particular when penetration levels start to make a significant impact on the power system. One solution to enable system performance to be studied which is particularly suitable for utilities is to apply historic time series and to derive load duration curves for the key components. Such curves give a much more comprehensive picture of the system compared to single, seasonal figures. Further statistical analyses and detailed investigations of phenomena can easily be performed.

As a by-product of such analysis, network planners will be able to specify non-firm connection agreements for future wind farm developments. The time series approach is appropriate for assessing the level of likely constraint for non-firm connections but may not identify worst case conditions which can be related to an infrequent but possible set of circumstances. In order to understand these worst case conditions it would be necessary to look at longer term patterns and the statistical relationship of influential factors.

The accuracy of the results depends on the quality of the wind data although this can be expected to improve with further wind farm installations. Forecasted wind output can be used in a similar way to determine system performance in real time and make necessary system adjustments to optimise system operation.

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