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Assessment of Protection Functionality and Performance with Respect to Declining System Fault Levels and Inertia Due to a Significant Increase of Inverter-based Generation on National Grid's Transmission System in the United Kingdom

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SUMMARY

This paper summarizes a study performed by National Grid UK to better understand the impact of declining fault levels and system inertia due to increasing penetration of renewable, inverter-based generation. The focus of this study was to investigate these impacts on transmission system protection and control equipment, as well as to explore possible mitigation strategies to address these impacts. Any mitigation actions to address these issues will be at a significant cost and therefore an in-depth understanding of these issues will be needed by any utility experiencing this phenomena.

Throughout National Grid's transmission network in the United Kingdom, the short-circuit current – once fed primarily by conventional synchronous generators – is being fed by an increasing percentage of renewable generation via power-electronics technology. With the proliferation of this power-electronics-based generation (also known as inverter-based generation), it is no longer possible to ignore the impacts to transmission system characteristics, especially changes in system fault currents and inertia. In addition, power-electronic-based generation has relatively more complex behaviour under power system faults than what is well understood from synchronous generator characteristics. The behaviour in response to a fault is significantly influenced by vendor-specific design of electronic control schemes, as well as the inherent fast-response (inertia-less) characteristics. Hence, the impact on transmission system protection is significantly different from that of conventional rotating-machine-based generation.

KEYWORDS

Inverter, low fault current, renewables, low inertia, protection

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INTRODUCTION

Throughout National Grid’s transmission network in the United Kingdom, the short-circuit current – once fed primarily by conventional synchronous generators – is being fed by an increasing percentage of renewable generation via power-electronics technology. With the proliferation of this power-electronics-based generation (also known as inverter-based generation), it is no longer possible to ignore the impacts to the transmission system characteristics, especially changes in system fault currents and inertia. In addition, power-electronics-based generation has relatively more complex behaviour under power system faults than what is well understood from synchronous generator characteristics. The behaviour in response to a fault is significantly influenced by vendor-specific design of electronic control schemes, as well as the inherent fast-response (inertia-less) characteristics. Hence, the impact on transmission system protection is significantly different from that of conventional rotating-machine-based generation.

How these changes will affect the dependability and security of protection and control schemes is a concern that is being discussed globally across the industry. Working groups have been initiated at CIGRE and IEEE, where industry experts are in the process of developing guidelines that will help the industry to understand and address these upcoming challenges.

This paper summarizes the findings of a study focusing on how lower fault current and lower system inertia will impact the existing protection and control schemes, and what mitigation strategies exist to address these impacts.

IMPACT OF LOW FAULT CURRENT

It is widely expected across the industry that an increase of system in-feeds from power-electronics-based applications (e.g., HVDC interconnectors, renewable energy, and FACTS technologies) will lead to a decrease of fault current levels. In the following, the challenges these changes will create for protection and control schemes will be discussed.

Issue

The decline in fault currents has a direct influence on the measurements that are typically processed by transmission system protection to make secure and reliable decisions regarding whether or not to remove a faulty system element from the system. Based on the thermal limitations of inverters, they will only provide a fault current contribution of about 1.0 pu to 1.5 pu of their rating. This is programmed within the inverter control and protection algorithm and is manufacturer-dependent. For generation that is directly connected to the transmission system, the grid code will dictate how long the fault current contribution must be maintained.

National Grids “Future Energy Scenarios 2016” [14] provides an example estimation of the evolution of fault levels for Great Britain (GB), as shown in Figure 1, which indicates the percentage Fault Current Change from 2017-2026.



Fig Z Consumer Power Scenario: Fault Current Change from 2017-2026

Impact

The reduced fault current will impact different protection relay principles differently.

Overcurrent Principle

Lower fault current will cause sensitivity issues for overcurrent protective functions where they may fail to operate (or be delayed so that they will not be properly coordinated).

For an assessment of how changing fault currents impact the overcurrent protection performance, the future development of minimum and maximum fault current levels should be investigated. The minimum fault current is critical for setting pickup levels in overcurrent functions. The overcurrent function is typically used as backup protection or for the supervision of unit (differential) and non-unit (distance) protection. During protection studies, the minimum current is normally determined by selecting an N-1 contingency that provides the lowest fault current.

The maximum fault current is used for inverse overcurrent elements to determine the correct time dial (time grading) setting. The time dial is selected so that correct coordination is achieved when the maximum fault current is seen by the relay.

The maximum fault current is not expected to change as significantly as the minimum fault current (data suggest that some regions in the UK could experience as much as an 80% decrease in the minimum fault current) and shouldn't change more than 15% for most regions. The disparity between the changes in the minimum and maximum fault currents is explained by the fact that the minimum fault current occurs midday, when a strong contribution of solar PV energy is available. During this time, the synchronous generation will be at a minimum. The maximum fault current occurs during evening hours when only a limited amount of renewable (inverter-based) energy generation is available. In this case, synchronous generation will be providing most of the power.

Distance Protection Principle

Distance protection functions calculate the fault impedance from the measured fault voltage and fault current to determine if the fault is in the protection zone. The reduced fault current will cause a reduced fault voltage because the effective source impedance of inverters is higher than the source impedance of synchronous generators. The accuracy of the distance element will be impacted if the fault voltage drops below a certain voltage level. This is particularly critical on short lines, as the line impedance is low. The source-impedance-to-line-impedance ratio (SIR) is a value that is used by National Grid to determine whether non-unit protection (distance elements) can be used on a particular line. The SIR ratios will increase in relation to the growing amount of inverter-based generation. This is important because, when the SIR ratio is above 30, non-unit protection becomes unreliable as the accuracy decreases and operating time increases.

Differential Protection Principle

The differential protection principle is used for busbar, transformer, and line protection applications. The basic differential principle measures and sums all currents entering the protected object and monitors that the sum is not equal to zero for the detection of an internal fault. The basic principle is not affected by lower fault currents as long as the total fault current exceeds the pickup settings for the differential elements. However, the impact of changing fault current characteristics (e.g. phase angle changes) due to the application of inverter based generation requires further study.

Mitigation of Low Fault Current Issues

The issues associated with declining fault currents can be mitigated by one of the activities described in the following subsections.

Revision of Settings on Existing Relays

Many of the existing protection schemes use the overcurrent principle as a backup or supervisory function. As long as the fault current does not drop below a minimum pickup fault current level, the existing overcurrent function can be used, but a settings adjustment must consider the reduced fault current. It is common practice in some countries, and even mandated by regulation in others, that overcurrent protection settings and coordination need to be reviewed if fault currents change beyond a certain level. This project used a minimum fault current change of 10 to 15% as recommended and required by NERC reliability standard PRC-027 and National Grid guidance documentation as a

criterion to review and reset the existing relays. A separate task investigated the different protection applications in National Grid’s transmission system and estimated the required efforts for the review and protection settings revision work. In addition to the actual revision work, it was proposed that National Grid develop an automated evaluation system that can automatically monitor and evaluate the fault currents for the different applications and check the pickup settings and coordination of all overcurrent elements as the system evolves and changes over time.

Replacement of Relays

In some instances, the revision of settings on existing relays was not able to mitigate the effect of the decrease in fault current and increase in SIR ratios. In these cases, the replacement of protection relays is required. The replacement of non-unit (distance) protection by unit (differential) protection is required on lines where the SIR ratio will increase to above 30. The replacement of overcurrent protection relays with voltage-restrained or voltage-controlled overcurrent relays is required when existing relays cannot securely be set to differentiate between fault and load current.

Conclusion – Mitigation of Low Fault Current Issues

Based on the study, the abovementioned mitigation activities appear sufficient to address the predicted fault current changes in the UK at this time. However, more detailed analysis is still needed. In addition to the reduced fault current contribution, the fault current may not include a negative or zero sequence current contribution, which may require revising loop selection and directional elements to address these changes.

Impact of Low Fault Current on Control

As the majority of control functions are event-based systems (operational tripping schemes, auto-close, etc.), no direct impact due to declining fault currents is expected.

IMPACT OF LOW SYSTEM INERTIA

As today’s inverters do not have an inherent inertia, (their fault current response is determined by control software), the overall power system inertia will decrease with the increasing percentage of inverter-based generation.

The ENTSOE report “Future System Challenges Ahead with High Penetration of PEIPS (Power Electronic Interfaced Power Sources)” [6] provides an example estimation of the evolution of system inertia for Great Britain (GB), as shown in Figure 1, which indicates the percentage of the year that inertia is at or above specific levels.

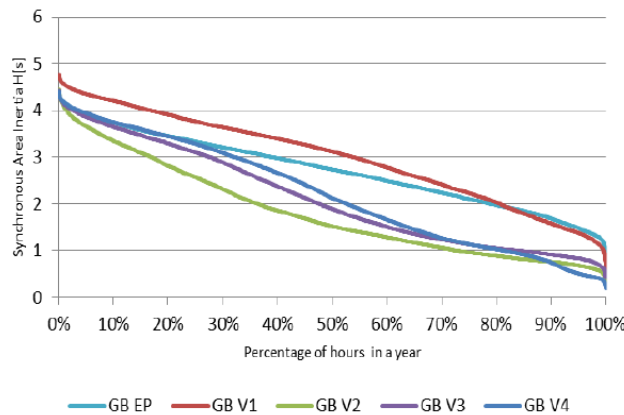


Figure 1. Evolution of GB system inertia 2016.

Impact of Low System Inertia on Transmission Protection

Issues

The stability of the system is challenged with lower power system inertia. Several of the source documents reviewed [4,6,11,12] mentioned the risk for frequency excursions beyond what is currently experienced due to reduced generation/load balance direct control and lower system inertia.

Impact

Lower system inertia impacts the reliability and security of protection equipment by presenting the challenges described in the following subsections.

Minimum Fault Clearing Time for Power System Stability

The requirements on minimum fault clearing time would have to change, and faster protection operations would be required to maintain stability in power systems with low inertia. The existing requirement in the UK for fault clearing time is about 120 to 150 ms. Much faster fault clearing times cannot be achieved with the existing protection and breaker equipment. A marginal improvement in total tripping time can be achieved by design changes that would use newer and faster protection relays and the removal of auxiliary trip relays. Not only would such a redesign of the existing protection schemes require a detailed investigation, but the cost for implementing new protection schemes and designs throughout the National Grid system would be significant, if not prohibitive. Therefore, the system inertia should be maintained at a level that allows for the presently-required fault clearing times. This was also pointed out in the ENTSOE report “Future System Challenges Ahead with High Penetration of PEIPS”. [12]

Stability during Power Swings

After power system events where the load/generation balance is changed temporarily or permanently, the power system must adapt to the new conditions. This causes power swings in the system until a new stable operating point is found. These swings will be more severe in a system with low inertia. The power swing blocking function may be required in non-unit (distance) protection relays, particularly on long transmission lines where the resistive-reach of the distance element is extended and may cover an area that can be entered by a power swing impedance trajectory. Alternatively, the use of double unit protection could be implemented, but it would lack the back-up protection provided by Zone 2 of the current non-unit protection.

Rate of Change of Frequency (RoCoF)

Generator protection functions that use the RoCoF criteria for the detection of islanding conditions to trip the generator must be set with lower sensitivity in order to not misoperate in response to the higher RoCoF values in the future.

Frequency Excursions

Wider frequency excursions have the potential to affect relays that do not have an adaptive frequency feature. If the protection function is tuned to the fundamental frequency, then a deviation of the power system frequency will create inaccurate results that could lead to under-functions or over-functions of protection relays. Protection relays used to protect generation units from out-of-step situations may also require adjustment.

Mitigation of Low System Inertia Issues

The issues observed with low system inertia can be mitigated by one of the following activities.

Replacement of Equipment

The replacement of equipment must be considered if the system operator cannot maintain the system inertia at a level that would allow the typical fault clearing times of today’s equipment. A marginal improvement in total tripping time can be achieved by design changes that use newer and faster protection relays and the removal of auxiliary trip relays. Such a redesign of the existing protection schemes will require a detailed investigation. The cost for implementing new protection schemes and

designs throughout the National Grid system are estimated to be significant. Different solutions to maintain the required system inertia are currently under review.

Revision of Settings and/or Configuration of Existing Relays

Non-unit line protection relays may require the use of power swing blocking functions to avoid operating on power swing events. As it is difficult to predict what the system inertia value will be in a particular year, it is proposed that National Grid review all lines with an impedance greater than 15 ohms (primary) to determine if a power swing function should be used.

The settings of RoCoF relays used on generators may need to be reviewed and adjusted to the new system conditions. The settings must be able to securely detect an islanding situation, but not operate for system disturbances that create frequency excursions. The focus of the project was on transmission protection, so this was not investigated further.

Implementation of New Solutions

New solutions may be required to mitigate some of the issues caused by low system inertia.

Travelling Wave Protection. The present development of modern traveling wave line protection [9] provides the potential for faster fault detection with higher sensitivity than conventional relay principles. Both of these features will be beneficial for system conditions with low inertia. The traveling wave relays also offer the advantage of the settings being largely independent of system topology, and would therefore not be sensitive to large shifts in system inertia when blocks of generation are online or offline.

System Dynamic Monitoring. Real-time synchrophasor measurements are already being applied to system monitoring and, eventually, may enhance or even replace the state estimator in system operations. Tasks associated with visualizing, storing, and retrieving the phasor measurement data are being worked on by the industry, and the application of the synchrophasor measurement technology in the area of system protection is now also a reality [1]. Time-stamped synchronized measurements offer a tremendous benefit for protective relay applications. These real-time measurements represent actual system conditions at any given time and can potentially be utilized in relay protection.

Wide-Area-Based Protection and Control System. Relays are set based on predetermined, *static* system conditions that are typically either maximum or minimum. However, the configuration of the system constantly changes and may not necessarily be at its maximum or minimum, but somewhere in between, as the system conditions vary due to changing loads, network switching operations, or faults. Therefore, the relay settings based on the extreme system conditions may not necessarily result in a correct relay operation for a given system condition in a *dynamic* state.

The relays that are set to make a trip decision based on synchrophasor measurements constitute a class of adaptive or predictive protective devices. At this time, these devices appear to have a very promising future. System protection engineers are very interested in applying real-time synchrophasor measurement technology to system protection and control functions in order to achieve the kind of adaptability that could account for all possible system operating conditions.

Presently, there are only a few examples of the use of synchrophasors for wide-area protection schemes. However, synchrophasor-based schemes are typically used for monitoring to validate and improve network management to enable more efficient operation of the network including the decision making process for thermal-related operational tripping schemes (OTS).

The further objectives of these schemes will be to integrate these measurements into intelligent control schemes which will:

- Enable wide-area protection schemes and/or adaptive protection in the future (advisory or automatic protection setting group change).

- Detection of the penetration level of PEIPS
- Management of low inertia issues (as part of an OTS).

Improvements to the Grid Code

The following improvements can provide mitigation to the impact of low inertia on both protection and control functions.

Defining Inverter Requirements. Wind generators have the capability to provide inertia to the system as the rotor blade is a rotating mass. Today, grid codes do not typically require the contribution of inertia, and, therefore, the wind farm interconnection does not provide the more complex interface that would provide inertia. In some countries, changes to the grid code in this respect are being considered to improve the inertia of the system.

System Planning/Dispatch. Through controlling the penetration level of the PEIES, however this will cause the restriction of using renewable energy resources.

Impact of Low System Inertia on Transmission Control

Issues

Sudden changes in generation or load (such as that resulting from a large generating unit trip) may result in system frequencies deviating from their normal ranges. The initial frequency response of the system during and after such an event is mainly determined by the inertia of the system.

Impact on Control Schemes

The control schemes used on the transmission system include operational tripping, auto-switching, delayed auto-reclose, and synchronising schemes.

The auto-reclose scheme itself will not be affected by a change in system inertia. However, whenever the closing of the breaker is supervised by a synchronising device, the changed system inertia must be addressed with settings adjustments. It is common practice at National Grid to monitor the following criteria to supervise the closing of the breaker:

- Slip speed (frequency difference)
- Phase angle
- Energizing check

The slip frequency and phase angle criteria are directly related to the system inertia and must be set accordingly.

The coordination of under-frequency load shedding schemes as part of the system frequency control will become more complex in the future as renewable generation sources supporting the power system frequency are connected to distribution feeders. This problem must be resolved in the distribution system and, thus, was not further investigated as part of this transmission-focused project.

The auto-reclose practice and remote breaker closing via SCADA may need to be adjusted to close the line end with the strongest source first.

Impact on System Frequency Control Schemes

Frequency Excursions

Large frequency excursions will cause load shedding or generation shedding schemes to operate.

RoCoF

The rate of change of frequency will be significantly affected by system inertia. The RoCoF settings for the “loss of main” protection must be reviewed and adjusted to avoid unnecessary generation tripping.

Frequency Response

To guarantee system stability, and to avoid large frequency excursions, it will be required that the system frequency control respond faster to load/generation imbalances with low inertia. Large frequency excursions will result in the operation of load shedding or generation shedding schemes.

It was not the focus of this project to investigate the impact of changed fault currents and reduced system inertia on local control schemes. However, because of the huge impact on system control schemes, a detailed analysis of the impact is proposed as future work.

Mitigation of Impact of Low System Inertia on Transmission Control

The transmission control issues observed with low system inertia can be mitigated by one of the following activities.

Settings Adjustment

Synchronizing devices must be set to values that allow for the closing of the circuit breakers even with higher system inertia. It is assumed that one synchronizing device needs to be reviewed per line. The weak end will typically reclose by a dead line check and monitors only the line voltage. The follower terminal typically utilizes a synchronizing device.

Implementation of New Solutions

To improve the visibility of the system and improve the response time of control systems, PMU-based systems are implemented and used. PMU-based systems have already proposed to enhance protection functions. The same system could be utilized to monitor and control the system. In the UK, there are several PMU projects utilized for this purpose.

Improve Grid Code – Define Inverter Requirements

The following improvements can provide mitigation to the impact on both protection and control functions.

Defining Inverter Requirements

Wind generators have the capability to provide inertia to the system as the rotor blade is a rotating mass. Today, grid codes do not typically require the contribution of inertia, and, therefore, a wind farm interconnection does not provide the more complex interface that would provide inertia. In some countries, changes to the grid code in this respect are being discussed to improve the inertia of the system.

System Planning/Dispatch

Through controlling the penetration level of the PEIES, however this will cause the restriction of using renewable energy resources.

FUTURE WORK

The focus of this study was to investigate the impact of declining fault currents and lower system inertia on transmission protection and control equipment. The project involved a high-level review of the provided data. The increasing amount of renewable generation will change the power system characteristics – particularly fault current characteristics. Fault current characteristics could not be fully investigated during this study.

The following is a list of proposed future work to further investigate this phenomena:

- Proof-of-concept study to develop and trial the assessment of the necessary processes in order to prepare for large-scale automated Wide Area Protection Coordination (WAPC) study.
- Investigate the models that have been made available to commercial software companies by organizations such as EPRI and the European project MIGRATE to verify if they are adequate for modelling the impact on protection of the UK system.
- A study of ride-through times of inverters and the impact on protection should be carried out to ensure backup systems perform as expected.
- With increased penetration of inverter-based generation, there is a risk for frequency excursions beyond what is currently experienced due to less generation/load balance direct control. Implementation of synthetic inertia may alleviate this concern, but relay performance should be evaluated for the maximum expected frequency deviation. These frequency excursions have the potential to affect relays that do not have an adaptive frequency feature. Any relays that do not perform correctly under these conditions will need to be considered for replacement with relays that have the adaptive frequency feature.
- System stability and power swings become of concern where there could be large blocks of inverter-based generation being disconnected. The fault clearing time requirements will ask for a faster protection operating time to maintain stability in the system with a lower inertia. It is assumed that the unit and non-unit protection can meet these requirements. The overcurrent coordination interval and the breaker failure time delays currently used must be reviewed and revised to meet future requirements.
- System stability and power swings become of concern where there could be large blocks of generation being disconnected, resulting in rapid shifts of load flow on major transmission corridors and interconnectors. While these wide-area protection issues are best addressed by real-time control by synchrophasors or operator control, there may be a need to implement power swing blocking and/or power swing tripping in line protection relays. This need should be investigated to highlight the risks and develop mitigation methods and solutions.
- A significant study will need to be undertaken to determine if synthetic inertia would be feasible on the UK system. This would include determining what areas would need synthetic inertia, how much would be required, and its location to provide the support traditionally provided by synchronous machines. In parallel with this, an investigation would need to be performed to determine how a synthetic inertia system would be operated and controlled.
- Inverter-based generation is mostly controlled by switching actions of electronics. As a result, the load and fault currents include a much higher harmonics content as synchronous generators. For that reason, with the growing penetration of inverter-based generation, the future fault currents will include much higher harmonics content. This can already be observed on faults close to wind or solar farms where the fault current is predominantly provided by inverter-based generation. Detailed analysis should be conducted to show how severe these effects are and solutions developed to mitigate any risks to protection and control reliability and dependability.

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