Electric Power Systems Research 143 (2017) 281–291

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Verification and estimation of phase connectivity and power injections in distribution network

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ARTICLE INFO

Article history:
Received 10 March 2016
Received in revised form
19 September 2016
Accepted 7 October 2016
Available online 24 October 2016

Keywords:
Distribution network model
Phase estimation
Phase connectivity
Distribution utility
Advanced distribution management system

ABSTRACT

Distribution utilities are facing a new set of challenges for efficient and optimal operation of modern (active and more dynamic) distribution networks. To address these challenges, utilities are relying on sophisticated algorithms and software that require accurate phase connectivity models and three-phase state estimation. Without this data, the operational benefits of optimization software packages are reduced and limited.

This paper presents a method for verification and estimation of phase connectivity for a predefined set of nodes with three-, two- and single-phase connections. These nodes are formulated as accurate nodes with questionable phases. Accordingly, the bus injections (loads and/or distributed generations) and overall network's operation condition are estimated. The proposed method requires the minimum set of real-time measurements and utilizes all other available quasi real-time and pseudo measurements. The method is simulated on two characteristic test systems: 1) modified IEEE 13-bus benchmark network, and 2) real-world 186-bus distribution feeder through realistic study cases of distribution network model coordinator.

1. Introduction

1.1. Motivation and aim

Power distribution networks have been changing their design and operation strategies in order to support the concept of a smart grid. The main changes in distribution network modernization are: 1) growth of renewable and distributed generation (DG); 2) increasing number of electric vehicle charging stations; 3) growth of controllable loads and energy storages; 4) adding distribution automation and smart devices with local automation for fast auto-restoration and reconfiguration and other. The operation of the distribution networks have become more dynamic with bi-directional power flows, high voltage issues, unreliable load safety margin, and multiple sources in fault conditions.

The first challenge for distribution utilities is to provide the optimum system operation in various conditions. In the 21st century, various groups (customers, regulatory entities, and governing bodies) are putting the strong demands on utilities to enhance the network resiliency and efficiency, to ensure modern power quality requirements, to continually improve the quality of service and customer satisfaction, and to increase revenue. The second challenge is to promptly respond to these requirements.

These challenges can be resolved only with efficient distribution network management through monitoring, optimization, network development planning [1], and operation planning. The convergence of these tasks in distribution utility is increasingly clear [2], while the availability of close to real-time distribution network models is essential for these tasks [3]. Even advanced concepts of the distribution network management which consider utility and customer owned resources, require the best available quality of the network model [4]. One of the important components of a Distribution Network Model (DNM) is the Phase Connectivity Model (PCM). Unfortunately, the PCM is not error free and it is subjected to the various uncertainties in real-time operation.

Topology (connectivity) model errors have a more significant influence on the estimated operation condition than the parameter errors, emphasizing the issue that this condition can be significantly biased, especially on unmonitored areas [5]. If more real-time sen-

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[1] Main abbreviations, indices, and symbols used throughout the paper are stated below for quick reference, while others are described in the text.

http://dx.doi.org/10.1016/j.epsr.2016.10.013
0378-7796/

Nomenclature[1]

Abbreviations

ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
CA	Confirmed area
CB	Confirmed bus
DG	Distributed generation
DLP	Daily load profile
DNM	Distribution network model
EUB	Equivalent unconfirmed bus
PCM	Phase connectivity model
PCVE	Phase connectivity verification and estimation
SCADA	Supervisory control and data acquisition
UA	Unconfirmed area
UB	Unconfirmed bus
WLS	Weighted least-square

Indices

A, B, C	Phases A, B, and C, respectively
est	Estimated value
gr	Grouped measurements
i, j	Bus indices ($i, j = 1, 2, \ldots, N_b$, where N_b is total number of network buses)
(k)	Iteration count
min (max)	Minimum (maximum) value
mid	Middle value (between minimum and maximum)
ϕ, X, Y, Z	Phase indices

Symbols

P, Q	Active and reactive powers, respectively
$\boldsymbol{P}, \boldsymbol{Q}$	3-Dimensional vectors of phase active and reactive powers, respectively
$\boldsymbol{x}$	State vector
$\boldsymbol{z}$	Measurement vector

sors are added, the calculation results will be more accurate in areas close to the sensor location. However, there is a significant possibility for less accuracy in other unmonitored areas [6]. Based on our experience, the distribution network operation with the existence of phase connectivity errors can cause several unpredictable situations, such as: 1) false/hidden alarms and risks of overload and voltage violations; 2) misleading results of outage prediction; 3) false/hidden nested outages; 4) non-optimal actions proposed by certain optimizations; 5) miscalculated available current reserve and proposed outage restoration actions; 6) jeopardized safety of field personnel due to (un)planned work; 7) misleading results of load (re)allocation in distribution network planning; 8) hidden operational problems, such as level of losses and feeder unbalances and other.

Utilities are looking for the cost-efficient solutions to deal with PCM errors that usually come through updates from Geographic Information System [7], in order to avoid introducing new errors into their DNM. In addition, the latency in the process of updating the DNM is to be reduced, because the distribution utilities typically have *reactive approach to this problem which requires proactive approach*, and it should be changed in the future. It means continuous verification and estimation of phase connectivity model, with minimal field check effort required.

1.2. Literature review

The previous work in this area is quite limited. Ref. [8] identifies the phase on single-phase taps (laterals and transformers) using the linear regression between smart meters based and upstream Supervisory Control And Data Acquisition (SCADA) based voltage measurements. Authors in Ref. [9] proposed the method to identify phases based on high-precision synchrophasor measurements. However, there is the question of the time horizon: how long will it take distribution utilities to deploy these devices in each feeder and in the necessary quantities? Ref. [10] runs the linear state estimator with high measurement redundancy, taking into account voltage, active and reactive power measurements from smart meters. Iterative phase swapping of the highest residual measurements is used for phase connectivity correction. Authors in Ref. [11] proposed the mixed integer optimization for identification of household phases, which requires the measurements on each service (distribution) transformer. This method is applicable to networks where three-phase service (distribution) transformers feed dozens of house-holds through single-phase secondary lines. Ref. [12] considered the correlation between smart meters and SCADA-based voltage measurements for automatic identification of service point (customer) phase. Similarly, Ref. [13] proposed approach for customer phase verification based on correlation factors of voltage profiles for customers fed by common transformer and voltage magnitude (both retrieved from smart meters). Authors in Ref. [14] suggested Tabu search to identify the lateral phase, based on SCADA measurements and load profiles, with the objective of minimizing the mismatch between the calculated and measured power flows.

We can conclude that the all previously published methods require measurements available throughout the distribution network, either real-time or Advanced Meter Infrastructure (AMI) based. That makes these methods limited to widespread application, due to the following reasons: 1) typically utilities have no real-time measurements available throughout the distribution network; 2) many distribution utilities have not deployed AMI due to the significant cost (it is questionable when will it become fully available in the future); 3) where AMI has been deployed, it is restricted only to pilot areas, and 4) when AMI is available for the entire distribution network, quite often the smart meter functionality is restricted to energy consumption readings and status events. In addition, these methods are focused on addressing a specific instance of phase connectivity error, such as customer phase or service (distribution) transformer phase, but these methods do not provide a generalized approach.

1.3. Contributions

This paper proposes the low cost and fast algorithmic approach for phase connectivity verification and estimation (PCVE) for a predefined set of nodes, where three-, two-, or single-phase elements are connected with no constraint to specific type of element. This set of nodes consists of: 1) suspicious nodes detected proactively or reactively; 2) nodes from an area, which is included in a PCM update, and 3) nodes where maintenance, repair and load balancing activities have just been completed. The proposed PCVE algorithm is based on the three-phase state estimation procedure with equality and conditional constraints. The minimum required input data is trusted real-time (SCADA-based) measurements (one per feeder), and the known number of phases (1, 2 or 3) in nodes under verification. This data is typically available in the most distribution utilities worldwide and it makes foundation for widespread usage in many utilities, including ones not equipped with AMI. Additional (non-SCADA based) data that utilities have confidence in, such as (quasi) real-time data deeply embedded in the network, or AMI-based data are also taken into account. This data can additionally improve the feasibility and quality of the solution, but it is not mandatory required for the PCVE algorithm. Consequently, there is the possibility for widespread use, without additional investment for intelligent equipment in primary dis-