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# Graph Theoretic Approach to Solve Measurement Placement Problem for Power System State Estimation

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**ABSTRACT**: The meter placement problem involves selection of meters, number, type and place. This paper describes graph theoretic approach to solve the measurement placement problem for power system state estimation. The measurement configuration is designed for IEEE 14 bus system. Utilizing the proposed measurement system configuration the network observability is tested for P-δ and Q-V models by triangular factorization of the gain matrix. The designed metering scheme assures network observability and accomplishes better accuracy and bad data processing requirements for state estimator. The developed method can be used as measurement systems planning tool for power system state estimators.

**KEYWORDS:** Bad data detection, Meter placement, Network observability, Remote terminal unit, State estimation.

## I.INTRODUCTION

Within the energy management system, state estimation is a key function for building network real time model that is static mathematical representation of current condition of an interconnected power system [7]. State estimation is a standard practice at power system control centres, responsible for providing reliable real-time database for analysis, control and optimization functions. The state of electrical power system is defined by the vector of voltage magnitude and angle at all network buses. The static state estimator is the data processing algorithm for converting redundant and not so reliable meter readings and other available information about the network connectivity in to an estimate of the static state vector [1].

The real-time modeling of a power network usually follows following procedure involving [7]:

- Data gathering
- Network topology processing
- Observability analysis
- State estimation (SE)
- Processing of bad data and
- Identification of network model

Network topology processor identifies energized and de-energized electrical islands and is performed before state estimation and other related functions such as observability analysis and bad data processing [14]. Static state estimator requires a set of real-time measurements consisting of bus injections, line flows and bus voltages as input which are collected through the Supervisory Control and Data Acquisition System (SCADA) that redundantly observes the system state along with a topology processor that determines the system topological model based on the telemetering of circuit breaker statuses [8]. It may occur that the errors affecting state estimates are not compatible with their standard deviations. Most frequently, this may happen due to the presence on bad data among the measured quantities. Therefore, post-state estimation procedures incorporated to the state estimator is identification and elimination of the bad data. The most commonly used tool for this purpose is the normalized residual test [5].

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Also, to achieve reliable state of power system, the network should be observable with the available set of measurement. If the power system network is observable, state estimation may proceed. Otherwise, additional measurements are required to be added. Hence, an observability test should be executed prior to performing the state estimation. The network observability can be tested for P-δ and Q-V models by triangular factorization of the gain matrix. The obsevability algorithm checks that the information available in the form of measurements is sufficient to fulfil the computational needs of state estimator or not [16].

Power system state estimators requires a set of redundant measurements, which are appropriately chosen according to the type, number and location of the measurement points in the supervised electric network [6]. The main objective in designing metering scheme is to satisfy the requirements like Cost, Accuracy, Reliability, and Bad Data Processing for power system state estimator [5]. In late 90's, researchers started giving importance to the development of cost effective and reliable metering scheme which can yield accurate state estimation. The measurement data are usually power flows, power injections and bus voltages [12]. In 1996, a meter placement method developed by Mesut E Baran et al. The main objective of authors in designing a metering scheme was to satisfy cost, accuracy, reliability and bad data processing requirements. The developed method was utilized for designing the measurement system configuration on IEEE 14 bus system [5].

The measurement placement method using Simulated Annealing aims at attending to the requirements such as observability and reliability- taking in to account the associated monetary costs was developed by Alessandra B Antonio et al. in 2001. The developed method was utilized for designing the measurement system configuration on IEEE 30 bus system [6]. In 2006, the optimal meter placement method using hybrid Genetic Algorithm and Simulated Annealing (GA/SA) for solving optimal measurement placement was developed by Thawatch Kerdchuen et al. [33]. The metering configuration for 10-bus and IEEE 14 bus system was presented and P-δ observable concept was used to check the network observability.

The state estimation is a mathematical procedure by which the state of electric power system is extracted from a set of measurement. In standard SE, in order to relate measurements and non linear equations, the following model is used:

$$z = h(x) + e$$

Where, z is the (m×1) measurement vector, h(x) is the (m ×1) vector of non linear functions, x is the (2n ×1) state vector, e is the (m×1) measurement error vector, n is the total number of buses in the power system network and m is the total number of measurements.

The state estimator is a mathematical algorithm formulated to minimize the error between a real time measurement and a calculated value of the measurement. The minimization criterion often selected is the weighted sum of error squares of all the measurements. The estimator favors accurate measurements over the less accurate ones by weighing the errors with the measurement standard deviation ($\sigma_j$) [12].

$$\min J(x) = \sum_{j=1}^{m} \left( \frac{e_j}{\sigma_j} \right)^2$$

The condition for optimality is obtained at a point when the gradient of J(x) is zero. From weighted least square method, the iterative equation can be obtained as follows:

$$\Delta x = \left( H^T R^{-1} H \right)^{-1} H^T R^{-1} \left( z - h\left(x^k\right) \right)$$

$$H = \frac{\partial h(x)}{\partial x} = \begin{bmatrix} \frac{\partial h_1(x)}{\partial x_1} & \frac{\partial h_1(x)}{\partial x_2} & \cdots & \frac{\partial h_1(x)}{\partial x_{Ns}} \\ \frac{\partial h_2(x)}{\partial x_1} & \frac{\partial h_2(x)}{\partial x_2} & \cdots & \frac{\partial h_2(x)}{\partial x_{Ns}} \\ \vdots & \vdots & \cdots & \vdots \\ \frac{\partial h_m(x)}{\partial x_1} & \frac{\partial h_m(x)}{\partial x_2} & \cdots & \frac{\partial h_m(x)}{\partial x_{Ns}} \end{bmatrix}$$

Where, $N_s = 2n-1$

$$W = R^{-1} = \begin{bmatrix} \frac{1}{\sigma_1^2} & & & \\ & \frac{1}{\sigma_2^2} & & \\ & & \cdots & \\ & & & \frac{1}{\sigma_m^2} \end{bmatrix}$$

For the n bus system, considering one of the bus as a reference, n-1 angles and n voltage magnitudes are to be calculated. The state estimation Jacobian (H) always has 2n-1 columns and large number of rows based on number of measurements made. The gain matrix is defined as

$$G = H^T R^{-1} H$$

While the power system not only has SCADA, but also has Phasor Measurement Units (PMUs) placement, the sub problem is formed by PMU placement and SCADA measurements [32]. The state variables measured by PMU are assumed true value and the known state variables are $x_1$. The unknown state variables are required to be estimated by reduced power system state estimation model.

## II.PROPOSED METHOD OF MEASUREMENT PLACEMENT

The meter placement problem involves selection of meters (number, type and place) [5], [6]. The main objective in designing a metering scheme is to satisfy the following requirements.

1. Cost: The total investment cost for the metering scheme should be kept to minimum. This involves the cost of meters, Remote Terminal Units (RTUs) and communication system.
2. Accuracy: The Measurements obtained through metering scheme should yield the state variables with desired accuracy.
3. Reliability: Power system network should be observable and there should be enough redundancy so that state estimation can be carried out even after loss of measurements or meter failure.
4. Bad data processing: Measurement system should allow state estimator to detect and eliminate bad data from the available set of measurement.

Proposed measurement placement method is based on network graph theory. The metering scheme assures that each branch of power system network is incidental by power injection or flow measurements at either ends or a flow measurement and an injection measurement at one of its terminal node. Selection of meter locations also assures least requisite of RTUs. For observability, the presence or absence of the flow is of importance and not the numerical value of the flow. If a branch that neither has a flow measurement on it nor an injection measurement at one of its terminal nodes, that branch does not come into the matrix H and thus it does not play any role either in observability analysis or in state estimation.

The proposed method gives the greatest priority to power injection measurement at the buses of maximum adjacency to reduce the meter requirements for network observability. The redundancy can be considered as a function of the accuracy requirement in the state estimation. Always measuring quantities should be more than the necessary minimum number to make provision for eliminating erroneous quantities from the measurement set to ensure accurate state of the power system. Hence, at the second stage, branches consisting power injection measurement at one of it terminal node are identified and power flows are measured through such branches to increase redundancy. Further, to enhance redundancy, voltages at all additional RTU locations are measured.

The meter placement method proceeds as follows:

- Read bus data, initialize measurement set of interest by injection measurements at all the zero injection buses in the power system network.

- For n bus power system network, read line data and prepare n x n adjacency matrix A= [$a_{ij}$] where; $a_{ij}$ =1, if $i^{th}$ bus is incident to $j^{th}$ bus and aij =0, if otherwise. Modify adjacency matrix by making all $a_{ii}$ =0, as these elements of matrix represent the bus itself.
- Compute total ones of each row of modified adjacency matrix. Identify buses of maximum (p) and minimum (q) adjacency. Place RTU and measure power injections at the buses of adjacency p, p-1, p-2 ……., till p, p-1, p-2 ……., = q+2.
- Identify branches contain no power injection measurement at one of its end, place RTU and measure injection at any end. Add power injection measurements at the buses of q+1 adjacency and voltage measurements at all RTU locations till redundancy becomes ≥ 1.
- Update line data file by removing all the lines comprising of injection measurements at both ends. Measure power flows through the remnant lines such that minimum requisite of additional RTUs. Measure voltages at additional RTU locations.

## III.MEASUREMENT CONFIGURATION ON IEEE14 BUS SYSTEM

Adjacency matrix for IEEE 14 bus system is shown below.

$$A=\begin{array}{c|cccccccccccccc|c}
 & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 & 11 & 12 & 13 & 14 & \text{Ones}\\
\hline
1 & & 1 & & & 1 & & & & & & & & & & 2\\
2 & 1 & & 1 & 1 & 1 & & & & & & & & & & 4\\
3 & & 1 & & 1 & & & & & & & & & & & 2\\
4 & & 1 & 1 & & 1 & & 1 & & 1 & & & & & & 5\\
5 & 1 & 1 & & 1 & & 1 & & & & & & & & & 4\\
6 & & & & & 1 & & & & & & 1 & 1 & 1 & & 4\\
7 & & & & 1 & & & & 1 & 1 & & & & & & 3\\
8 & & & & & & & 1 & & & & & & & & 1\\
9 & & & & 1 & & & 1 & & & 1 & & & & 1 & 4\\
10 & & & & & & & & & 1 & & 1 & & & & 2\\
11 & & & & & & 1 & & & & 1 & & & & & 2\\
12 & & & & & & 1 & & & & & & & 1 & & 2\\
13 & & & & & & 1 & & & & & & 1 & & 1 & 3\\
14 & & & & & & & & & 1 & & & & 1 & & 2\\
\hline
\end{array}$$

At the first stage, interesting measuring quantities are;
Power injections at buses 2, 4, 5, 6, 7, 9, 10, 12, 13, 14
Voltage magnitudes at buses 2, 4, 5, 6, 9, 10, 12, 13, 14
RTUs locations 2, 4, 5, 6, 9, 10, 12, 13, 14

Updated line data file after removing all the lines comprises injection measurements at both ends is shown below.

| Bus $n_l$ | Bus $n_r$ | R p.u. | X p.u. | 1/2 B p.u. |
|---|---|---|---|---|
| **1** | **2** | 0.01938 | 0.05917 | 0.0264 |
| **1** | **5** | 0.05403 | 0.22304 | 0.0246 |
| **2** | **3** | 0.04699 | 0.19797 | 0.0219 |
| **3** | **4** | 0.06701 | 0.17103 | 0.0064 |

| | | | | |
|---|---|---|---|---|
| 6 | 11 | 0.09498 | 0.1989 | 0 |
| 7 | 8 | 0 | 0.17615 | 0 |
| 10 | 11 | 0.08205 | 0.19207 | 0 |

🟥 **Existing RTU Locations** 🟩 **Additional RTU**

At the second stage following measurements are added in the metering scheme:

Power flows on branch (2→1), (5→1), (2→3), (4→3), (6→11), (8→7), (10→11)
Voltage Magnitude at bus number 8.

Fig 1 shows the proposed measurement configurations on IEEE 14 bus system. Out of 122 possible measurements metering scheme utilizes 44 measurements & redundancy becomes 1.63.

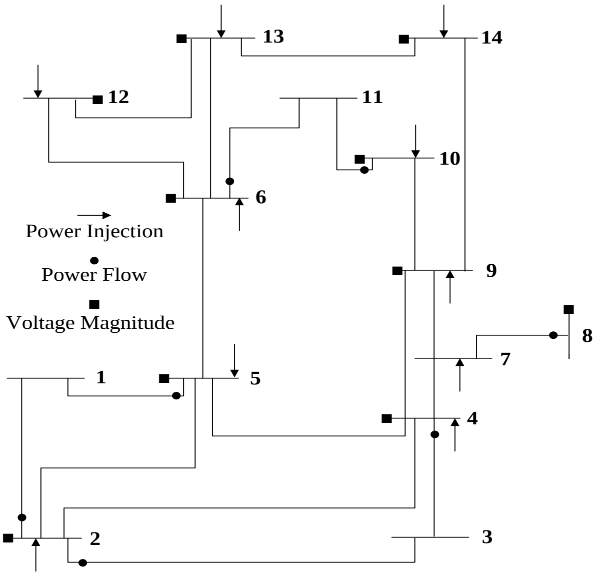

Fig. 1 Meter placement on IEEE 14 bus system using proposed method

The metering scheme consists: 10 RTUs, 10 power injections, 10 voltage magnitudes and 7 power flows.

## IV. TEST RESULTS AND COMPARISON

Estimated state obtained by utilizing the proposed metering scheme, hybrid GA/SA and the metering scheme of Mesut E Baran et al. is shown in the table 1 below.

| Bus No. | --------------- Estimated State --------------- | | | | | |
|---|---|---|---|---|---|---|
| | Proposed Metering Scheme | | Mesut E Baran et al. | | Hybrid GA/SA | |
| | Voltage Magnitude \|V\| | Bus Angle δ (Degree) | Voltage Magnitude \|V\| | Bus Angle δ (Degree) | Voltage Magnitude \|V\| | Bus Angle δ (Degree) |
| 1 | 1.040 | 0.000 | 1.060 | 0.000 | 0.754 | 0.000 |
| 2 | 1.028 | -2.368 | 1.045 | -2.286 | 0.713 | -4.182 |
| 3 | 1.014 | -6.311 | 1.030 | -6.071 | 0.936 | -11.513 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | 1.021 | -5.057 | 1.034 | -4.915 | 0.830 | -9.991 |
| 5 | 1.021 | -4.299 | 1.034 | -4.170 | 0.810 | -8.677 |
| 6 | 1.076 | -6.844 | 1.080 | -6.861 | 0.968 | -11.752 |
| 7 | 1.058 | -6.403 | 1.068 | -6.374 | 0.940 | -11.796 |
| 8 | 1.067 | -6.372 | 1.080 | -6.374 | 0.953 | -11.734 |
| 9 | 1.061 | -7.137 | 1.067 | -7.133 | 0.980 | -12.699 |
| 10 | 1.061 | -7.211 | 1.066 | -7.221 | 0.979 | -12.670 |
| 11 | 1.069 | -7.080 | 1.071 | -7.102 | 0.984 | -12.293 |
| 12 | 1.070 | -7.238 | 1.072 | -7.275 | 0.982 | -12.465 |
| 13 | 1.068 | -7.337 | 1.070 | -7.303 | 0.999 | -13.567 |
| 14 | 1.058 | -7.786 | 1.060 | -7.688 | 1.139 | -17.337 |

Table: 1 Estimated State Using Different Measurement System Configuration: IEEE14 Bus System

Fig 2 shows errors in estimated voltage magnitudes computed with the use of different measurement system configurations.

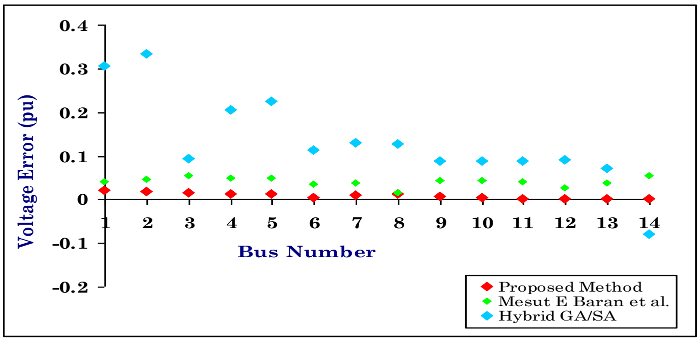

Fig. 2 Voltage Magnitude Errors: IEEE14 Bus System

Fig 3 shows errors in estimated bus angles computed with the use of different measurement system configurations.

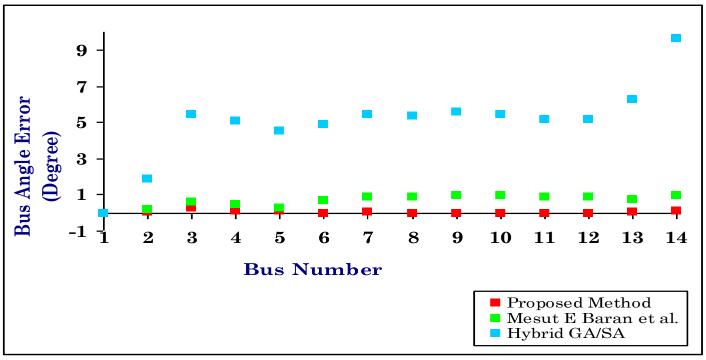

Fig. 3 Bus Angle Errors: IEEE14 Bus System

## V.CONCLUSION

Using the simulations developed herein, the state variables are estimated with the use of proposed measurement system configuration. Estimated state variables are compared with estimations obtained through the metering schemes of Mesut E Baran et al. and Hybrid GA/SA.

The proposed measurement system configuration accomplishes better bad data processing and observability requirements for state estimator compared with the metering scheme obtained through the hybrid GA/SA. Also, the proposed measurement configurations yields much accurate state of power system than the metering schemes of Mesut E Baran et al. and hybrid GA/SA. Moreover, the proposed method acquires cost effective measurement system configurations compared with Mesut E Baran et al. When SCADA measurements are combined with PMU, the direct measurement of state variables with enough accuracy will be available through PMU data. On the modified power system network excluding PMU buses, the proposed measurement placement method can be utilized to configure SCADA measurements and state variables can be estimated using reduced state estimation model. The developed method of measurement placement can also be implemented in the existing state estimators as an off- line measurement systems planning tool.

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