Power Flow Convergence and Reactive Power Planning in the Creation of Large Synthetic Grids

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***Abstract*—To encourage and support innovation, synthetic electric grids are fictional, designed systems that mimic the complexity of actual electric grids but contain no confidential information. Synthetic grid design is driven by the requirement to match wide variety of metrics derived from statistics of actual grids. In order to scale these systems to 10,000 buses or more, robust reactive power planning is needed, accounting for power flow convergence issues. This paper addresses reactive power planning and power flow convergence in the context of large synthetic power grids. The iterative algorithm presented by this paper supplements a synthetic transmission network that has been validated by a dc power flow with a realistic set of voltage control devices to meet a specified voltage profile, even with the constraints of difficult power flow convergence for large systems. The algorithm is illustrated with an example new synthetic 10,000 bus system, geographically situated in the western United States, which is publicly available and useful for a variety of research studies. An analysis is shown validating the synthetic system with actual grid characteristics.**

***Index Terms*—Power flow convergence, power system analysis, power system planning, reactive power planning, synthetic power grids, voltage control.**

I. Introduction

SYNTHETIC power grids are fictitious test cases designed for applications in power systems research, development, and demonstration. Their key feature is the systematic validation to ensure that they replicate characteristics of actual grids, including size, complexity, structure, parameters, and behavior. Free from confidential data, these cases are able to be widely published and shared. Hence the grids are useful for cross-validation and publication of research results, allowing peer researchers full access to the same synthetic data sets.

This paper builds on an existing network synthesis algorithm, extending the substation and transmission line placement process to consider the reactive power planning requirements and other complexities related to system power and voltage control. The new developments lead to full and realistic ac power flow solutions, meeting the challenges introduced as the system scale becomes large. First, Section II provides a background on synthetic power grids and the topics of power flow convergence and reactive power planning. Section III then addresses the challenges in finding an initial ac power flow solution on a large scale synthetic grid, to explain the motivation of our approach. Section IV introduces a new synthetic power grid of 10,000 buses, which provides a case study for analyzing the power flow convergence issues mentioned. The detailed algorithm for reactive power planning in large synthetic grids is presented in Section V, using the 10,000 bus test case as an example. Section VI compares the characteristics of the example test case to those of actual grids, validating both the presented method and the new synthetic system. Then Section VII concludes the paper.

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II. Background

A. Synthetic Power Grids

Some existing public test systems, such as the IEEE cases [1], are commonly used in power systems research, but their small size and limited complexity does not fully meet the needs of the research community today. Newly-developed grid data sets that are larger in size and have characteristics and properties similar to actual grids, while maintaining the ability to be shared publicly, have many benefits for power system innovation. One example [2] discusses making a large transmission grid for dc power flow studies, based on public data for continental Europe. This approach mimics the existing grid rather than using a synthetic method. A recent report [3] points out both the usefulness of having more public power data available and several approaches that are being used to make more use of the data that is available, including building transmission networks.

Fundamental to the synthetic approach, [4]–[9] highlight properties of power grids' structure, viewed from a complex network and graph theory perspective. These observations are applied to generating realistic network topologies in [10]–[14]. Reference [10] focuses on generating the topologies themselves, using a small-world model without any consideration of location, while [11], [12] take geographically-based approaches and [13] uses a clustering-based method. Reference [14] points out the challenges associated with modeling the variety of power system topologies in different places.

The approach of [15] and [16] builds on previous work by integrating the spatial, topological, and electrical requirements to make full power flow cases. The method starts with geographic data and uses an iterative dc power flow solution, anchored in statistical analysis of actual grids. Results have yielded 150-bus and 2000-bus test systems, fully public with demonstrably similar properties to actual grids. Extensions of these methods are given in [17] for economic studies and [18] for dynamics. Additional developments in validation and extension are found in [19]–[21], including two more synthetic grids with 200 and 500 buses. The present paper builds upon the approach of [16] and is the first study that has scaled network synthesis of full power grids to ten thousand buses, with a focus on reactive power planning and power flow convergence.

B. Power Flow Convergence

The standard non-linear power flow equations for ac power system solutions are solved iteratively. The conventional Newton-Raphson method is described in [22]. When these methods were first being applied to computer simulations, and as the size of the systems studied increased, it was noted that the Newton-Raphson power flow solution, being non-linear and iterative, is not guaranteed convergence [22]–[24]. This is still an active area of research, and several factors can affect convergence such as the problem conditioning, voltage stability characteristics, and the choice of initial values for the variables [25]. Fractal domains of attraction make predicting or guaranteeing convergence to a specific solution difficult [26], [27]. Reference [28] describes an application of homotopy solution methods, which have been proposed to improve convergence for cases that are perturbed further from the solution. Power flow convergence and analyzing the solvability of cases is applicable to voltage stability and dynamics studies, and has been studied in these contexts [29]–[32]. For many studies, the key to good convergence (if a solution exists at all) is a good initial guess; this presents a problem for synthetic systems which have no previous solution and do not have reactive compensation in place, a problem which this paper addresses.

C. Reactive Power Planning

Reactive power planning has many conventional optimization methods to add capacitors and other devices to an existing transmission system [33]–[36]. Methods are available to optimize over many objectives: installation cost, real power losses, fuel cost, voltage profile, and voltage stability [35]. Most of these methods, however, require a convergent initial power flow solution, and sometimes also require the initial voltage profile or other constraint to be met. The main purpose of these methods is incrementally adding reactive power support devices to an existing grid. Furthermore, there are computational limitations in many of the methods that prevents scaling to many thousands of buses, especially when a large number of devices must be placed. Building on this work, the problem addressed by this paper involves adding resources to a case without any existing devices or solution, with the objectives being to meet statistical metrics of realism rather than minimizing cost (although synthetic generator cost curves are considered in the initial dispatch, leading to good starting solutions for ac optimal power flow solutions).

III. Challenges in Obtaining Initial AC Power Flow Solutions for Large-Scale Synthetic Grids

Modeling power system loads as constant real and reactive power means that even the smallest systems might have no ac power flow solution, or multiple solutions. A bus with fixed real and reactive power will have a maximum loading, above which there is no solution, based on the impedances of the connecting lines and voltage of remote buses. Within this loading constraint, there will often be at least one low-voltage solution in addition to the expected solution closer to nominal, due to the nonlinearities of the power flow equations. For cases where multiple solutions exist, the initial guess of a Newton-Raphson power flow will determine which solution, if any, is reached by this method [29].

In large systems, these constant power situations combine across interconnected buses to make a correct solution even more difficult to find, if one even exists. Often the non-existence of solutions can be interpreted as the inability of the required amount of real or reactive power to be transferred from available sources. In the case of real power, the typical formulation of the power flow problem requires that each generator's MW set point be specified beforehand except one slack bus. The slack bus must pick up whatever real power load and losses are not provided by the other generators. Hence the dispatching of the non-slack generators to meet the assumed load and losses has a significant impact the solution. For small cases, the slack bus can correct a higher relative error in the loss assumptions present in the dispatch, but for large systems even 1% error in the assumed losses could be far more than the slack bus is able to produce.

Synthetic transmission grids, created according to [16], are built initially using an iterative dc power flow solution, which models real power flows only, in a lossless approximation of the system. The generator dispatch used in this step, which is based on an economic dispatch with synthetic cost curves, must be adjusted to account for assumed losses, or the ac power flow will fail because the slack bus will be incapable of supplying all of the losses. Though generator participation factors are used as an outer-loop adjustment to account for losses, there must still be an initial inner-loop solution (using a single slack bus for real power mismatch, as in [22]).

Large system reactive power flows are even more likely to produce an unsolvable case, since the high X/R ratio of most transmission system branches prevents reactive power from traveling far, meaning reactive power must be supplied within a nearby region. If some region of buses does not have sufficient reactive power available from generators or other devices, it cannot be brought from very far away, causing the case to be unsolvable. Thus while for real power the main concerns are system-level (ensuring that the losses are distributed among all dispatched generators), for reactive power the concerns are largely localized, making sure that the net static reactive power in some neighborhood, summing the loads, losses, and shunt capacitors, is sufficiently supplied by nearby voltage-controlled devices like generators, subject to those devices' reactive power limits. In synthetic grids, no modeling of reactive power is done in the dc power flow, so there are no additional support devices and potentially many areas without sufficient support.

For large system cases which have a solution, getting the Newton-Raphson method to converge to that point depends heavily upon the initialization. A flat start, which is the most basic initialization option, refers to setting all bus voltage magnitudes to 1.00 per-unit and angles to 0°. There are additional assumptions, as to whether generators are at reactive power limits, which shunts are switched in, and where transformer taps are set, which would all also be initialized to some default in a full flat start. Basically, the assumption is that nothing from prior solutions is known. For smaller cases, reaching a good solution from flat start initialization is possible, but the large interconnect cases (e.g., EI or WECC) often do not flat start in many commercial software packages ([37], page 48). These solutions diverge, even when the original settings are maintained for shunts, taps, and generator limits. In practice, flat starts are not used for large interconnects; instead, new solutions are obtained by small modifications to an existing solution.

A solution technique that requires previous good solutions will not work for synthetic cases, which are being solved for the first time. Synthetic grids, created according to the method of [16], not only lack a previous ac power flow solution, but have no initial set of voltage control devices, including reactive power resources. A key problem in building large-scale synthetic cases is adding a realistic set of reactive power devices, coordinating them in a way that they have a reasonable solution that fits a desired voltage schedule, and then actually finding this solution, which will likely not be available from a flat start.

Power flow solution convergence is also affected by additional complexities, which, while not inherently unique to large-scale systems, are often found in them. Three-winding transformers are typically modeled as three equivalent branches radiating from a fictitious star bus; the equivalencing can produce negative reactances and reactances close to zero, which can complicate sensitivities in voltage regulation. A related issue is remote bus voltage regulation, where a generator, shunt device, or load tap-changing (LTC) transformer regulates a bus other than its own terminal, sometimes with multiple remote buses regulating the same bus. It is quite common practice, for example, for a generator to be modeled in the power flow as regulating the high-side bus of its step-up transformer (GSU) [38], [39]. These devices can fight one another and lead to convergence issues. Phase angle regulating transformers (PARs, also known as phase-shifters), can further complicate the power flow as they regulate real power flow and integrate impedance correction tables. Each of these issues must also be addressed in building synthetic systems that match the complexity of the actual grid.

IV. Case Study: Ten Thousand Bus System

To demonstrate the issues raised by Section III, and to serve as an example for the proposed algorithm of Section V, this section introduces a 10,000 bus synthetic power grid. The geographic footprint selected corresponds to the U.S. portion of the North American western interconnect (WECC). This region has a population of over 70 million, with census and

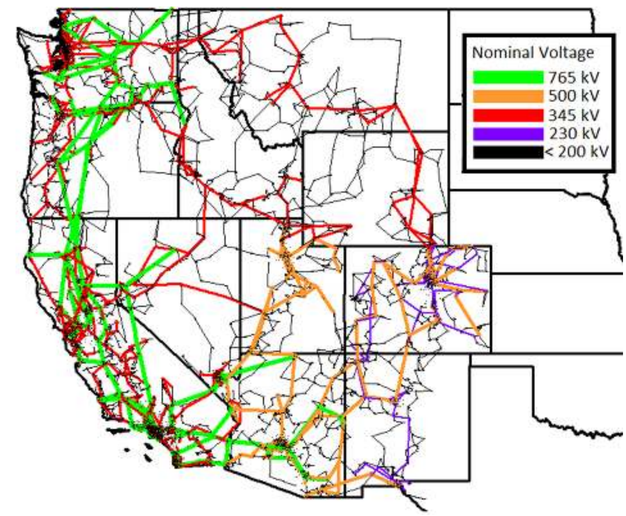

Fig. 1. Oneline diagram for the synthetic 10 k grid, showing the transmission line voltages. This case is totally fictitious, built from public information with a synthetic methodology, and does not represent the actual grid in this location.

generator data publicly available, as outlined in [15]. The region was divided into areas along state lines, with California, as the most populous state, being subdivided into five areas. Seven voltage levels were selected: 765, 500, 345, 230, 161, 138, and 115 kV, and each area was designed 2-3 voltage levels. The system has its generation and load substations placed from public information as well as a clustering method. Buses and transformers are assigned to each substation using the modified hierarchical clustering described in [21], and an initial generator economic dispatch is set. Then the transmission network is built through an iterative dc power flow solution, gradually adjusting to meet the statistics and metrics observed in actual cases. The full method is described in [15] and [16], with [21] giving details important to this step for large systems with multiple areas and multiple voltage levels.

Included in this case are 300 three-winding transformers, divided into three main types: GSUs, load step-down, and modified network transformer with a low-voltage tertiary. Parameters are calculated analogously to two-winding transformers, as in the metrics of [19], then converted to an equivalent set of three branches with a star bus, as they are typically modeled in commercial power flow solvers.

The result is a transmission system that has been validated with a dc power flow, but does not yet have an ac power flow solution. The oneline diagram can be seen in Fig. 1, and the basic statistics are given in Table I. This table includes devices that are added in the next stage, described in Section V.

Unsurprisingly, the case did not converge in an ac power flow initially, despite having a reasonable dc solution. Various contributing factors to this are those mentioned in the previous section, including the wide spread of voltage angles, limited reactive power resources, and three-winding transformers. Next, an implementation of the algorithm described in Section V was applied to the system, placing shunt capacitors and reactors, and setting the control points and tap settings for voltage control devices.

TABLE I
STATISTICS OF THE 10 K CASE

System Element	Number
Buses	10000
Substations	4762
Areas	16
Voltage levels	7
Loads	4899
Generators	2485
Transformers	2981
Transmission lines	9726
Three-winding transformers	300
Tap-changing transformers	294
Phase-shifting transformers	5
Switched shunts	387

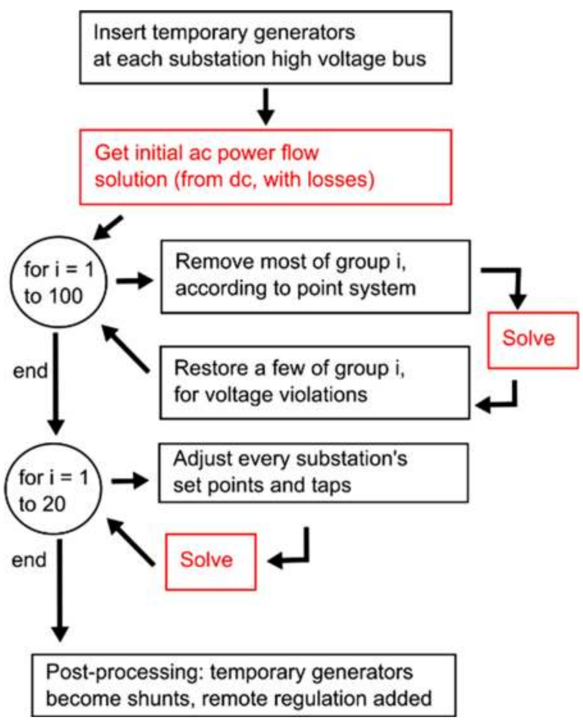

Fig. 2. Flow chart of synthetic reactive power planning algorithm.

The final synthetic grid, after the solution is obtained by the method of Section V, is available online in a variety of common formats [43], complete with specifications of buses, substations, areas, loads, generators, branches, and all the complexities described by this paper.

V. Algorithm for Synthetic Reactive Power Planning

The approach of this paper is to move incrementally from a dc power flow, for which the system has already been optimized with a good solution, to a full ac power flow solution with a reasonable set of reactive power support devices, as shown in the flow chart of Fig. 2. This is begun by initializing the system to have a very large number of devices controlling the voltage magnitudes of most system buses to a common, flat voltage. Then, iteratively, some of the temporary devices are removed at each step, adjusting the remaining ones by repeated ac power flow solutions.

A. Initial Power Flow Solution

Thus the first step was to take the 10,000 bus system transmission network and augment it with a large number of temporary voltage control devices. Most of these will eventually be removed, with the remnant becoming shunts. The temporary devices initially added to the system are generators, set to 0 MW active power output, with reactive power limits of $\pm$300 Mvar up to $\pm$800 Mvar, depending on the nominal voltage level. In the ac power flow, these will be modeled as PV buses, which at first will all be set to regulate their own bus to 1.04 p.u., to avoid generators fighting one another. Also for this reason, the temporary generators cannot be added too densely, as they tend to converge to undesirable solutions (for example, one generator producing 250 Mvar, with its neighbor on the other side of a low-impedance branch absorbing 230 Mvar). A compromise that works well in the analysis done by this paper is to initialize one temporary generator at the highest nominal kV bus in each substation, that is, 4762 in the 10,000 bus case. Of course, this is far more than a realistic number of shunts; however, the approach of this paper is to work backwards from a feasible power flow solution to a realistic set of devices.

The first ac power flow solution is initialized with all the temporary generators in place. The voltage angles are initialized to the solution of a dc power flow, including some compensation for an assumed real power loss percentage, such as 1–3%. The actual generators must be dispatched accordingly. Sometimes this loss percentage must be adjusted over a few iterations to get a convergent initial solution, but, thanks to the large number of temporary 0 MW generators, reactive power is not a concern in this first solution. The voltage profile is largely flat. For the synthetic 10 k case 1.5% assumed losses worked initially, with a convergent, flat solution.

Once the ac power flow has converged, the rest of the process is just a matter of making small changes to the system and analyzing at each step the impacts of the modifications on the resulting solution. The approach of this paper does this in two stages. The first stage removes a large number of the temporary generators, to match the expected number of shunt compensating devices. Then the second stage modifies set points and transformer taps to fit the voltage magnitude distribution desired.

B. First Stage Iterations: Removing Most Temporary Devices

For the first stage, consideration is made of the principle that reactive power effects are mostly localized. Thus many temporary generators can be removed at once, provided they are not clumped too tightly together. This leads to the strategy of selecting 100 groups of temporary generators, uniformly at random, and addressing each group in turn. In the 10,000 bus case, the 4762 temporary generators will be divided into groups with 47 or 48 devices each, dispersed across the system. Most of the temporary generators will be far geographically from

TABLE II
POINT SYSTEM FOR REMOVING TEMPORARY GENERATORS

Condition	Points
Nominal kV < 200	2
Nominal kV < 400	2
Substation generation > 100 Mvar	1
Substation generation > 10 Mvar	1
No. tie lines = 2	1
At least one tie line is sending MW	1
Nearest Q resource is 1 hop away	3
Nearest Q resource is 2 hops away	2
Nearest Q resource is 3 hops away	1
Second-nearest Q resource is 1 hop away	5
Second-nearest Q resource is 2 hops away	4
Second-nearest Q resource is 3 hops away	3
Second-nearest Q resource is 4 hops away	2

any other in its group. The approach of considering one group at a time strikes a balance between an intractable number of solutions and making too large of a localized change that could cause the solution to diverge.

Thus, the first stage will have exactly 100 iterations, with the following steps at each iteration (1) remove almost all of the temporary generators in the specified group, keeping a few *a priori*, (2) perform the ac power flow solution – restoring all generators in this group if it happens to diverge, and (3) restoring a few more of the original temporary generators as necessary for voltage support, based on the outcome of the solution.

The decision of whether a temporary generator should be removed is based on both factors related to the statistical observations from the actual grid and the specific localized reactive power needs of a neighborhood in the system. To integrate these notions, a points system is devised, with points corresponding to various heuristic factors that increase the likelihood that a temporary generator should be removed. The point system is specified in Table II, with considerations for voltage level, additional resources around, and the topology of the system. Before the solution, all temporary generators in a group except a few with the lowest points are removed. For the 10,000 bus case only 4 were kept before the solution from each group. After the solution has been reached, all buses above a nominal voltage of 50 kV are analyzed for voltage violations outside the range [0.96, 1.06]. For any bus that violate this constraint, which had a temporary generator removed this iteration, that generator is restored, up to a specified fraction. These fractions are chosen to match a maximum of 16% of total substations, which means in the synthetic 10 k case up to 7 out of the 44 removed temporary generators could be restored at each iteration to fix voltage violations. Many iterations did not need all of these restorations.

If, by chance, the power flow solution fails to converge at some point, that group of temporary generators is considered critical to the system, and fully restored. Since this is a rare occurrence and will only be 1% of the total devices, this will not significantly impact the statistics or the solution. For the example case of this paper, no iteration failed to converge.

The result of the first stage for the 10,000 bus case is that 387 out of the original 4762 temporary generators remain, providing voltage control and reactive power support to various needed regions of the system. The voltage profile remains high and flat.

C. Second Stage Iterations: Voltage Schedule Adjustment

Next, the second stage of the reactive power planning algorithm adjusts all the generator set points, actual and temporary, which were initialized to 1.04, as well as transformer tap settings. Before beginning these iterations, a realistic fraction of transformers is selected to be allowed to adjust their taps to control the voltage, with distinction made between network and generator step-up (GSU) transformers. These selections are made probabilistically. Unlike the previous iterations, the system admittance matrix must be reformed at each step, since the changing of taps affects it. While each iteration is therefore slower, the overall time of this stage is low since the parallel adjustment of each substation's set points only requires about twenty iterated solutions.

With each substation largely independent during the voltage scheduling iterations, this step of the algorithm can be decoupled. During initialization, the substation is assigned a target voltage, which will be selected uniformly from the range [1.035, 1.045]. Buses nominally in the range [200 kV, 400 kV] will be regulated to 0.002 above that, and those above 400 kV will be regulated to 0.003 above the substation schedule. These are of course small modifications to the general principle that system voltages should be made flat and high, recognizing that in real systems this ideal cannot be perfectly matched.

For any substation with a temporary generator or an actual generator attached directly to the network voltage buses, the voltage set points will be adjusted in the second stage iterations to reduce the difference between the actual bus voltages and their schedule. The changes made are small and discrete, so that each power flow solution is only a slight modification of the previous one, to avoid fighting between devices.

For transformers with an allowed tap-changing mechanism, these taps are also adjusted, in increments of 0.00625, to work on matching substation voltage schedules. For network transformers, the transformer is tapped as needed, maximum once per iteration, for the lower voltage bus voltage magnitude. For GSUs, the approach is slightly more complicated. If the high-voltage bus of the GSU already has another device controlling its voltage, the GSU and generator behind it work towards adjusting the generator's Mvar output to about 30% of the generator's maximum Mvar output, so that there will be plenty of reserve reactive power in the system. Otherwise, the GSU and associated generator must work to control the high-voltage bus's voltage magnitude.

Finally, the slight adjustments of the voltage scheduling iterations are complete, and the temporary generators are converted to shunt capacitors and reactors with the given reactive power set points. Many of the actual generators which are connected through a GSU are set to regulate the bus voltage of the high side of the transformer, according to [38] and [39]. For the synthetic 10 k case, it was then exported to a commercial power flow solver, and the solution converged as expected.

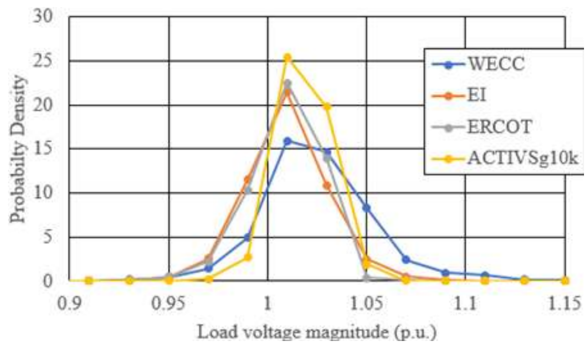

Fig. 3. Load bus voltage magnitude distribution of the synthetic 10 k case (yellow) compared to the distribution found in actual cases. The EI, WECC, and ERCOT cases studied are all summer peak base planning cases, from 2012, 2013, and 2016, respectively. Although the voltage profiles can change throughout the year, the 10 k synthetic case is designed to be a summer peak planning case, so it is compared to these.

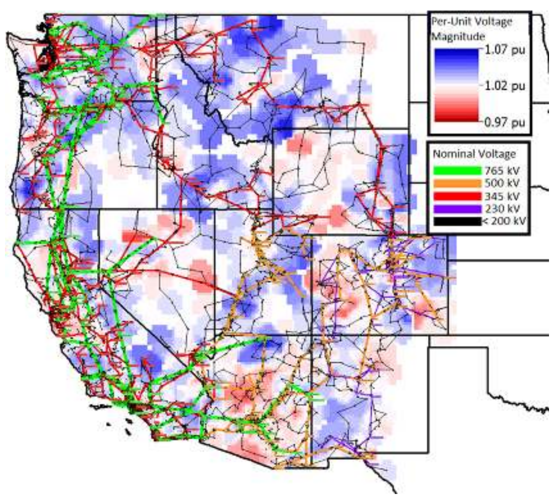

Fig. 4. Oneline diagram for the synthetic 10 k case, showing the transmission lines and a voltage magnitude contour [44]. The contour shows geographically the distribution of Fig. 3, with load bus voltages varying in the range [0.97–1.07].

VI. Comparison of Resulting Power Flow Characteristics to Actual Grid Observations

An analysis of actual grid data sets is fundamental to the synthetic grid approach. As in previous work [15], [16], [19], recent peak planning cases of major North American interconnects: the Eastern Interconnect (EI), the Western Interconnect (WECC), and the Texas Interconnect (ERCOT), are studied in this paper. Previous work has given statistics related to the proportions of load, generation, and power transmission elements, with a main focus on a dc power flow-based solutions and real power considerations. This section discusses metrics that are of additional importance when large system ac power flow solutions are involved, especially with regard to voltage and reactive power. Then the synthetic 10 k case is shown to meet these properties as a result of the last section's algorithm.

A. Voltage Magnitudes

The distribution of voltage magnitudes is an important consideration as synthetic grids move from a dc power flow, where all voltages are assumed unity, to an ac power flow. Load voltage is important because that is the delivery point of power, with the main objective being to keep the voltage close to nominal, higher, and flat across the system. These are exactly the characteristics observed in Fig. 3 for the distributions of nominal voltage magnitude for load buses in three major North American interconnects, matched by the profile of the synthetic 10 k grid. This distribution is also seen geographically on the one-line diagram of Fig. 4, using a contour [44]. Table III gives statistics of the distribution, showing the mean and standard deviation, which vary significantly in real interconnects.

TABLE III
Statistics of Load Bus Voltage Magnitude Distribution

Case	No. Buses	Voltage magnitude mean (p.u.)	Voltage magnitude standard deviation
EI	62650	1.009	0.038
WECC	20131	1.014	0.105
ERCOT	7003	1.010	0.034
Synthetic 10k	10000	1.020	0.012

TABLE IV
Shunt Reactive Power Devices in Actual and Synthetic Cases, as a Percent of Substations by Voltage Level

Case	No. Buses	% All Subs with Shunts	% Subs > 200 kV with Shunts	% Subs > 300 kV with Shunts	% Subs > 400 kV with Shunts
EI	62650	22	36	46	59
WECC	20131	17	41	66	65
Synthetic 10k	10000	8	32	32	63

B. Shunt Compensating Devices

Voltage objectives in base and contingency conditions are met in grids by adding and adjusting shunt reactive power devices, such as capacitors, reactors, static var compensators (SVCs) and synchronous condensers. This paper focuses on capacitors and reactors, which are most common, however the method is general and could be applied to other devices as well, simply by converting the remaining temporary generators to the appropriate actual reactive power source or sink. With a substation-oriented approach, the statistics given in Table IV for actual cases list what percentage of a case's substations have a capacitor or reactor modeled. Table IV also shows the dependence upon voltage level of the expected percentage of substations with reactive power compensation.

As can be seen, EI and WECC have 22% and 17% of all substations containing reactive power devices. There will be localized differences in specific areas' needs, modeling detail, and engineering design philosophies. When it comes to nominal voltage level, the trend is that higher-voltage substations are considerably more likely to have reactive devices. The synthetic 10 k case matches these properties. The total percentage is slightly lower than observed in EI and WECC, which allows for extra shunt devices to be added as needed for special-case situations or future developments.

TABLE V
NETWORK TRANSFORMERS (WITH LOW-SIDE NOMINAL KV > 60) OFF-NOMINAL TAP CONTROL

Property	EI	WECC	Synthetic 10k
Percent of network transformers with off-nominal tap ratio	68%	66%	63%
Percent of network transformers which are regulating low side voltage magnitude	44%	35%	33%
Percent of network transformers which control active power with phase angle regulation	1.6%	0.8%	0.4%
Percent of network transformers with impedance correction table	7.1%	0.7%	0.4%

C. Generator Voltage Regulation and Reactive Power Limits

The reactive power capability of synchronous generators is defined by a capability curve, where the boundary of possible reactive power supply is defined by the limiting factor of stator and rotor thermal limits and stability limits. However, in power flow analysis it is common to specify only a reactive power maximum and minimum value. These values vary substantially; for the purposes of these synthetic networks they are assigned by fuel type as a fraction of active power capacity, similar to the approach of [15].

The voltage set point of a generator assumes a voltage regulating scheme where the generator is attempting to maintain a certain bus voltage to some value. According to [38] and [39], power flow typically models generators which have a step-up transformer (GSU) as regulating the high-voltage bus to which the GSU is connected. In the EI and WECC cases, at least half of generators which are connected to a bus with a nominal voltage of 10–60 kV regulate a bus other than their own terminal.

D. Tap-Changing Transformers

Another important control device for system voltage is the under-load tap-changing transformer (LTC), as well as transformers which maintain a fixed off-nominal tap ratio that cannot be changed under load. For synthetic power grids, the transformer placement is done in the method of [15]; what is done in Stage 2 of the algorithm in Section V is to choose the devices that have off-nominal tap ratios and the subset of these which control the low-side voltage, plus the parameters on this control. Statistics on the prevalence of these two types of devices in actual cases is given in Table V, including the matching values for the 10 k system.

E. Phase Angle Regulating Transformers

As shown in Table IV, phase angle regulating transformers (PARs) are a small minority among transformers in interconnect cases, however, they are important to specialized purposes such as balancing active power between parallel paths and reducing loop flow through an area [40]–[42].

Often associated with PARs are impedance correction tables, which change the branch impedance according to the off-nominal phase shift value of the PAR. As the PAR taps from 0° phase shift to a significant shift such as 30° or more, the branch impedance increase significantly. Impedance correction tables are also used in some tap-changing transformers, but the focus is on ones associated with PARs. These tables have the following observed characteristics (1) They are approximately symmetric around a phase shift of 0° (2) the center impedance is the smallest (3) a good fit is quadratic.

Included in the synthetic 10 k system are four places with PARs and their corresponding impedance correction tables. They are manually added at a few critical inter-area interfaces to allow for additional control of the real power flows between areas.

F. Contingency Analysis

The 10 k system was tested in both base conditions and under 12,000 single element outage contingencies. In contingency conditions, the switched shunts were treated as discrete stepped devices, where first the solution solves with shunts in their base state, then shunts are able to switch discretely and iteratively to control the voltage at the device terminal.

Initially 300 contingency violations were found, either with transmission branch overloads or voltage out-of-range. Manual adjustments were made to address them, leading to a secure base case. Although contingency analysis was not included in the reactive power planning process, the system performed well in contingency conditions largely because of the heuristic point system of Table II that encourages more than one reactive power resource path from a bus.

VII. CONCLUSION

This paper addresses inherent challenges introduced when scaling synthetic power grids up to cases the size of continental interconnects. In these situations, ac power flow convergence issues become prominent, and must be addressed by an appropriate reactive power planning strategy.

Such a strategy is documented in Section V, which takes the approach of gradually converting from a dc power flow, which does not consider reactive power, to a reasonable ac power flow solution with the right number of shunt devices. The two stages of iterations handle reactive power planning in a way that is tolerant to power flow convergence difficulties.

Like actual large interconnects, this system has an ac power flow solution, but it cannot be reached by a flat start. The solution came from the iterative process described by Section V, gradually adjusting the case and resolving it. The result is a high-quality, realistic transmission system data set that meets both the validation metrics of [19] and the ac power flow voltage-based statistics described in Section VI. In size, realism, and complexity, this grid is well-suited as a test bed for research algorithms, demonstrations of new innovations, and public sharing and cross-validating of power system engineering developments.

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