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Need for Load Modeling in Short Circuit Analysis of an Inverter-Based Resource-Dominated Power System

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***Abstract*-- Short circuit models of transmission networks have not commonly included loads. The reason is that the fault current from synchronous generators are many times higher than the load current and highly reactive, and hence omission of load current does not reduce the accuracy of short circuit results. Nevertheless, this modeling practice may no longer be appropriate to an inverter-based resource (IBR)-dominated grid or grid region; the fault current of an IBR is comparable to load current and, depending on inverter terminal voltage, can have a considerable active component. This paper studies the impact of load modeling on fault analysis of IBR dominated grids. Specifically, the paper identifies potential simulation inaccuracy issues caused by lack of load modeling under IBRs and provides considerations to reduce the error and increase the fidelity of short circuit results. If these inaccuracies are not addressed, they may impact the behavior of protection relays in the simulation and risk incorrect protection relay configurations. This is turn could create risks of relay misoperation or failure to operate during power system disturbances.**

***Index Terms*—Load modeling, Renewable energy sources, Power system protection, Power system simulation, Short-circuit currents.**

I. Introduction

WITH increasing integration of renewable energy resources in the power system, the short circuit characteristics of the power system is expected to change [1]-[7]. Most commonly, these resources use a power electronic interface and hence are referred to as inverter-based resources (IBRs). This power electronic interface produces fault current signatures that are different from those of a traditional synchronous generator (SG) [2]-[7]. Specifically, the typical fault current contribution from a conventional SG, immediately after a short circuit and within the time frame of protection operation, is of high amplitude, uncontrolled, and highly reactive. By contrast, the fault current contribution from an IBR is of low amplitude, tightly regulated by converter control scheme, and with a dynamically changing phase angle depending on the inverter reactive power/voltage control mode.

These differences in the short circuit behavior of IBRs and SG lead to two impacts. First, large-scale integration of IBRs leads to potential misoperation of traditional protective relays [8]-[16]. Secondly, classical short circuit models and modeling practices may no longer apply to IBRs, and there is a need for revision of models and modeling practices [17]-[20]. The focus of this paper is on the second aspect, i.e., the required revision of traditional short circuit modeling practices in transmission networks with high share of IBRs.

A traditional modeling practice has been to not include loads in the short circuit model of a transmission network. This practice is justified in traditional SG-dominated grids since the fault current contribution from a SG is many times higher than load current and highly reactive; hence, omission of load current/model has negligible impact on the accuracy of fault analysis results. Furthermore, if the load is modeled then it is typically necessary to create realistic generator dispatch scenarios for the power-flow simulation to solve; this can require a significant resource to establish and maintain. In summary, excluding load from short circuit model has been a justifiable practice in a traditional SG-dominated power system.

While omission of load model is a valid assumption in a traditional SG-dominated grid, it may lead to inaccurate short-circuit simulation results in an IBR-dominated power system. The reason is that the amplitude of fault current of an IBR is comparable to that of nominal load current, and the fault current may contain a considerable active component, depending on a variety of factors including severity (i.e., type, location etc.) of fault and IBR control scheme. The latest implementation of IBR short circuit model in commercial fault analysis programs also allow for injection of active current by IBR [17]. As noted in [17], IBRs are voltage-controlled current sources (VCCS), i.e., current contribution during a fault is dependent on terminal voltage. To correctly determine terminal voltage (i.e., voltage rise across the step-up transformers and collector system) and resulting fault current contribution, it seems necessary that IBR injects active current along with reactive current. To numerically accommodate this active current, it may become necessary to include loads in the short circuit model. Without loads, this circulating active current may skew the amplitude and phase angle of simulated fault current flows, thus reducing the fidelity of fault analysis results [21]. It is therefore necessary to study the extent of such potential inaccuracies and potential

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need for modeling load in the short circuit model to reduce the inaccuracy.

Building upon [21], this paper studies the impact of load modeling on fault analysis of IBR-dominated grids. The objective is to determine the extent and impact of potential inaccuracies caused by lack of load model and provide considerations for reducing the error and enhancing the fidelity of fault analysis results. The contributions of this paper over [21] include: (i) studying the extent and impact of the error using actual transmission system models ensuring a realistic representation of loads and IBRs; (ii) studying the impact of IBR control on the inaccuracy issue; and (iii) providing and evaluating considerations for reducing the error. Specifically, three considerations have been studied: (i) Including all loads in the short-circuit model; (ii) Re-parameterizing the IBR short-circuit model to eliminate active current injection; and (iii) adding artificial load at IBR locations to locally absorb active current injection of IBRs. The effectiveness of these considerations has been studied, and the pros and cons have been presented.

II. Fault Current Characteristics of an Inverter-Based Resource

The fault current characteristics of an IBR is largely dependent on inverter control scheme. A key control design objective is to limit the amplitude of current within the thermal withstand capability of power electronics during short circuits. Thus, the amplitude of the sustained fault current contributed by a IBR is typically low, since it is constrained by the converter limiter to values close to rated current.

Fig. 1 illustrates the fault response of a Type-IV wind-turbine generator (WTG)-based IBR for a nearby and distant three-phase fault, showing that the amplitude of the positive sequence current (I_Total) is constrained within 1.1 pu. The figure further shows that the phase angle of IBR fault current is regulated, resulting in different active and reactive current components (I_Active and I_Reactive) under the two fault scenarios. Depending on the grid code/IBR interconnection requirement, an objective of this control is to satisfy applicable IBR dynamic reactive power support requirements (also known as fault-ride through (FRT) operation) during a fault. Prior to the fault, the inverter contributes mainly active current. Once the control system detects a fault (i.e., a large drop in terminal voltage), the active current contribution decreases and reactive current contribution increases. The split between active and reactive currents depends on inverter control active/reactive current priority as well as terminal voltage drop. Typically for Bulk Power System (BPS)-connected IBRs, the reactive current contribution is given priority and has the full current rating of the IBR available to it, while the active current contribution is constrained to the remaining current capacity. Under a severe fault where voltage drop is large, the reactive current may consume the full current rating of the IBR, and thus the fault current can be highly reactive, as in Fig. 1 (a). By contrast, under a distant fault where voltage drop is small, the reactive current contribution is low, the active current component can be close to inverter rating, and thus the fault current becomes highly resistive, as in Fig. 1 (b). This behavior can further be illustrated using Table I which presents a sample steady-state fault current contribution from a Type-IV WTG-based IBR as a function of terminal voltage. As shown, the fault current is highly active at terminal voltages close to 1 per-unit (pu). and highly reactive at terminal voltages close to 0 pu.

In summary, the fault current of an IBR is comparable to converter's current rating, and the split between active and reactive current depends on inverter control and terminal voltage. State-of-the-art IBR models in commercial fault analysis programs [17] also call for injection of both active and reactive currents during a fault. While this implementation is realistic, from the perspective of fault analysis the injected active current may lead to inaccurate results due to lack of load in short circuit models [21].

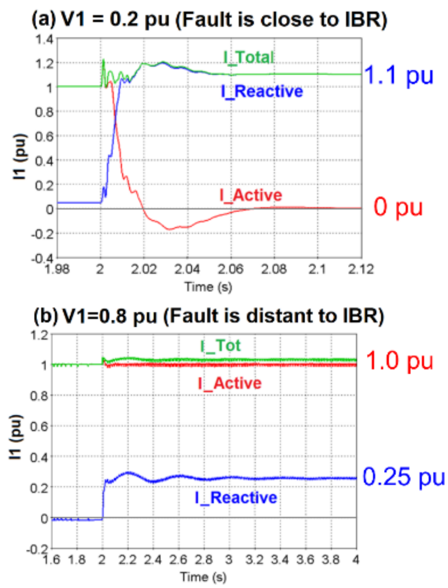

Fig. 1. Active and reactive components of the fault current of a Type-IV WTG under two fault scenarios: (a) nearby fault and (b) distant fault.

Table I. Sample steady-state fault current contribution versus terminal voltage for a Type-IV WTG-based IBR operated under FRT control mode with Q-priority.

Positive Sequence Voltage V1 (per unit)	Positive Sequence Current I1 (per unit)			PF Angle (I1/V1) (deg)
	Active Current	Reactive Current	Total Current	
1.00	1.00	0.00	1.00	0.00
0.90	1.10	0.07	1.10	-6.06
0.80	1.06	0.30	1.10	-15.62
0.70	0.99	0.48	1.10	-25.88
0.60	0.87	0.67	1.10	-37.55
0.50	0.67	0.87	1.10	-52.32
0.40	0.16	1.09	1.10	-81.76
0.30	0.00	1.10	1.10	-90.00
0.20	0.00	1.10	1.10	-90.00
0.10	0.00	1.10	1.10	-90.00

III. Expected Fault Analysis Accuracy Issues due to Lack of Load Model

To illustrate the problem caused by application of an IBR short circuit model which injects some combination of active and reactive current, the simple test system of Fig. 2 is considered. All per unit (pu) values are at 100 MVA and respective voltage base. A bolted three-phase fault is applied at the remote end of the line. For simplicity, the resistance of the SGs, generator step-up transformer, and transmission line has been ignored. Since there is no load, the pre-fault current from SGs is zero. After the fault, given that the impedance of the short circuit path is inductive, SG1 and SG2 contribute a reactive fault current of -*j*10.527 pu and -*j*3.158 pu, respectively, i.e., fault current lags generator internal voltage by 90°. Given that these two currents are in phase, the fault current becomes a scalar sum of contribution from each SG resulting in I_fault=-*j*13.684 pu. If resistance of network elements is included in the model, then SG contributes a small active current to accommodate for losses in those network elements and achieve a correct numerical solution. In an actual grid, the load is present, and the SG contributes active current during a fault to supply the load and network losses. However, in short circuit models, the load is ignored, and hence SG only produces active current to supply network losses, necessary for correct numerical solution.

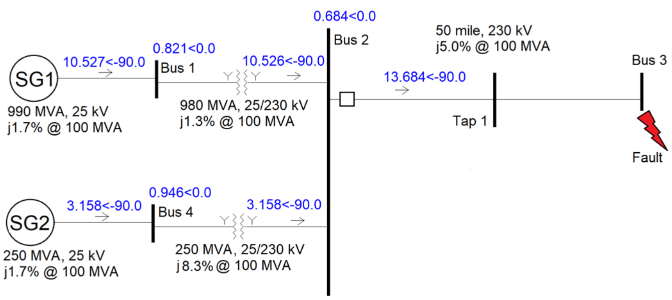

Fig. 2. Test system with SGs only.

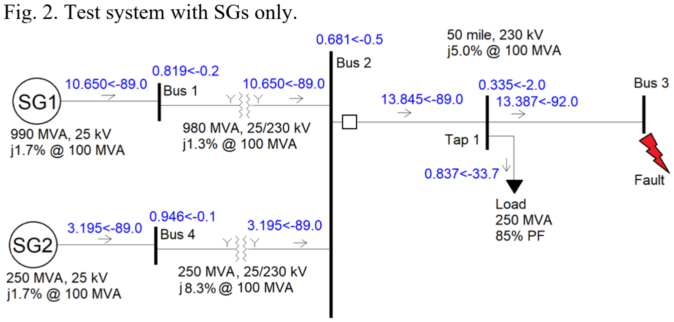

Fig. 3. Test system with SGs and load.

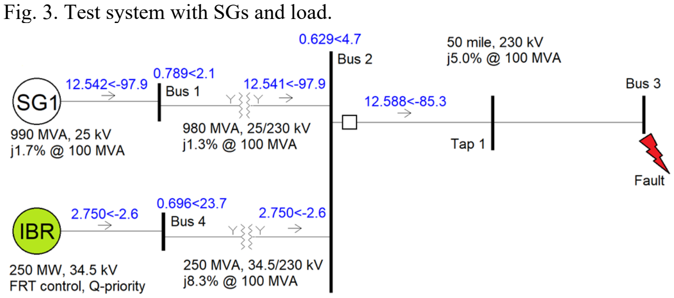

Fig. 4. Test system with SG and IBR.

To illustrate that adding load model does not significantly impact the accuracy of short circuit results in SG dominated systems, the same fault is repeated with a constant impedance load on a tapped bus in the middle of the line, as shown in Fig. 3. The current contribution from each SG and corresponding voltages are shown in Fig. 3. As can be seen, the load has negligible impact on short circuit results. There is a small change in the power factor angle of currents from SGs. This change is due to a small active current component being injected to accommodate the load.

To illustrate the impact of IBR, Fig. 4 shows the simulation of the same fault with an IBR replacing SG2. For simplicity, the collector circuit of the IBR and resistance of the IBR plant transformer have been ignored. The IBR represents a 250 MW Type-IV WTG-based wind park operating under FRT control mode with Q-priority. The fault results in IBR terminal voltage of 0.696 pu on Bus 4. Per model in Table I, the current contributed from the IBR lags the bus 4 voltage by an angle of 25.88°. This indicates active and reactive current contribution of 2.475 pu and 1.200 pu (on 100 MVA basis of the test system) respectively. This predominantly resistive fault current has the following impacts:

- The IBR injects 1.72 pu active power into the grid. Given that the network model is lossless, for a numerical solution to succeed, this active power must be absorbed by the only shunt element present in form of SG1. The angle between current and voltage of SG1 becomes -100°, meaning that SG1 is absorbing 1.72 pu active power. This is unrealistic; in an actual grid, loads absorb the injected active power, and SGs are protected against absorbing active current. A closer fault to the IBR induces a smaller voltage at the IBR terminal, thus making the fault current mainly reactive which reduces the error. In conclusion, lack of load model leads to incorrect flow of active current from IBR into SGs. This issue is more significant under distant faults where inverter terminal voltage does not drop too far below the nominal voltage; and

- The circulating active current component also skews the amplitude and phase angle of fault current, as the overall fault current becomes the vector sum of a resistive IBR current and a reactive SG current. In Fig. 4, the fault current is I_fault=12.588pu∠-85.3°, which has a lower amplitude and different phase angle compared to the case with SGs only. The circulating active current also skews the phase angle and amplitude of calculated short circuit voltages. As shown, the voltage phase angle of {Bus 1, Bus 2, Bus 4} is changed by {2.1°, 4.7°, 23.7°} and the amplitude is also changed. Given the impact of IBR-injected active current on the calculated short circuit current and voltage, load modeling may be necessary to correctly represent the active current flow and thereby improve accuracy of short circuit analysis.

IV. Demonstrating Case Studies

The issue is further demonstrated using two case studies on a portion of a 230 kV transmission network and an actual model of a north American transmission system.

A. Case 1: A 230-kV Test System

Fig. 5 shows the test system of this case which represents a portion of a 230 kV transmission system with high concentration of IBRs. There are 14 IBRs, each representing a Type-IV WTG-based wind park. The IBR control includes FRT functionality where WTGs operate in reactive current priority mode during a fault condition. A model of the test system has been implemented within a short-circuit program representing the IBRs by the VCCS tabular model [17]. This model allows IBR active current injection, the level of which depends on IBR terminal short circuit voltage. There are 4 SGs on Bus 3 denoted by SG1-SG4 and 12 transmission lines connected to Bus 1 denoted by Line 1-Line 12. A three-phase fault has been applied on Bus 2 resulting in a voltage of ~0.8 pu at IBR terminals. At this voltage, the IBR fault current is highly resistive. Line 1 and Line 2 carry the fault current from the IBR-dominated region, Line 6 carries the fault current from 4 SGs, and the rest of the lines carry the fault current from rest of the SG-dominated systems. The transmission network has a load on Bus 5 within the IBR region and at other locations throughout the network. The short circuit results have been compared with and without load to study the impact.

Table II compares the results with and without load. The current and voltage amplitudes are in per-unit (pu) based on a 100 MVA base at system voltage. With load model, the currents through lines Line 1-Line 12 are highly reactive. The reason is that the load on Bus 5 largely absorbs the IBR injected active current component, resulting in a highly reactive current contribution from the IBR region through lines Line 1 and Line 2. The fault currents of the rest of the lines are also highly reactive since they are supplied by a SG-dominated grid.

Without load model, the active current contribution from IBRs is injected into the transmission network through lines Line 1 and Line 2. Compared to the scenario with load model, the fault current of Line 1 and Line 2 increases in amplitude. The phase angle of current also changes due to presence of the active current component. Overall, the IBR region injects an active power of 14.1 pu into Bus 1. This active power needs to be absorbed by the rest of the system to allow a numerical solution. Following observations are made:

- Part of the IBR active current is absorbed by SG1-SG4 through Line 6. In total, these SGs absorb 2.3 pu active power which is unrealistic. This skews the amplitude and phase angle of current in Line 6; the amplitude changes from 3.9 pu to 5.6 pu and the phase angle with respect to Bus 3 voltage changes from -84.7° to -123.3°;

- The rest of the IBR active current flows into lines Line 3-Line 5 and Line 7-Line 12, thus skewing their phase angle and amplitude. The phase angle of current through Line 3 and Line 4 changes by 89.2° and 88.4°, respectively, and the amplitude of fault current is decreased from 22.6 pu to 21.0 pu when load is not modeled. The amplitude and phase angle of bus voltages also change due to the changed current amplitude and phase angle; and

- The magnitude of total fault current also changes from 22.6pu when load is modeled to 21.0 pu when load is not modeled. When load is not modeled, active current contributed by IBRs flows through the transmission network to SGs which results in higher voltage drop across the system. For example, Bus 1 voltage with load modeled is 0.8 per unit but when load is not modeled, Bus1 voltage reduces to 74%.

The above-mentioned numerical inaccuracies are caused by IBR active current injection level which depends on IBR control priority (i.e., active/reactive current priority) as well as terminal voltage drop. Hence, these factors impact the extent of the error. To demonstrate this, a number of faults close to the IBR region of Fig. 5 were simulated, and the results were compared with and without load model. This fault imposes a large voltage drop across IBRs terminal, which leads to a predominantly reactive IBR current contribution. In all cases, the error in current/voltage amplitude due to lack of load model was less than 5%, and the error in phase angle was less than 6°.

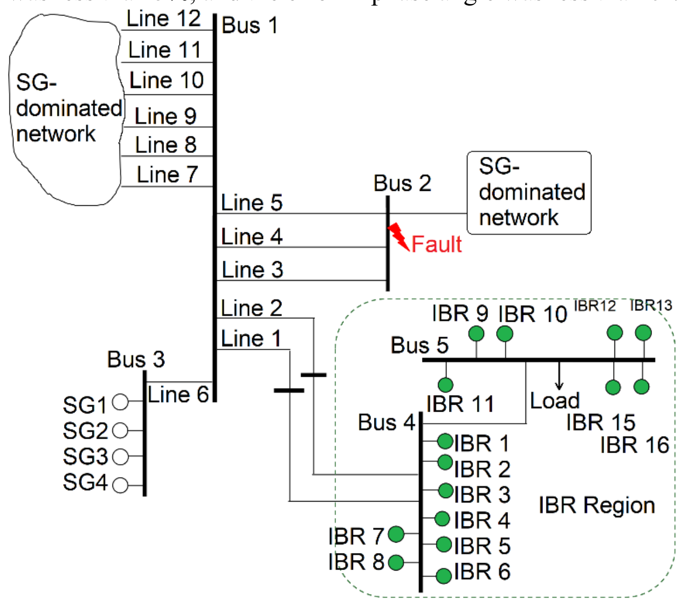

Fig. 5. The test system of Case 1, Section IV. A.

TABLE II. COMPARISON OF SHORT CIRCUIT RESULTS OF FIG. 5 WITH AND WITHOUT LOAD MODEL.

Bus Voltage				
Bus	V1 amplitude (pu)		V1 phase angle (degree)	
	With load	Without load	With load	Without load
Bus 1	0.80	0.74	-1.1	9.2
Bus 2	0.00	0.00	0.0	0.0
Bus 3	0.80	0.75	-1.1	9.2
Bus 4	0.84	0.76	-0.8	21.9
Bus 5	0.84	0.76	-0.9	22.0
Branch Current				
Branch	I1 amplitude (pu)		I1 phase angle (degree)	
	With load	Without load	With load	Without load
Line 1 (from Bus 4 to Bus 1)	2.6	9.7	-78.3	15.7
Line 2 (from Bus 4 to Bus 1)	2.6	9.5	-78.3	15.7
Line 3 (from Bus 1 to Bus 2)	0.5	2.3	-63.8	25.4
Line 4 (from Bus 1 to Bus 2)	0.7	2.1	-70.0	18.4
Line 5 (from Bus 1 to Bus 2)	21.4	20.7	-80.7	-70.5
Line 6 (from Bus 3 to Bus 1)	3.9	5.6	-85.8	-114.1
Line 7 (from Bus 1 to SG-dominated network)	2.9	4.1	102.4	75.6
Line 8 (from Bus 1 to SG-dominated network)	2.9	4.1	102.4	75.6
Line 9 (from Bus 1 to SG-dominated network)	1.7	2.4	102.1	74.9
Line 10 (from Bus 1 to SG-dominated network)	1.7	2.4	102.1	74.9
Line 11 (from Bus 1 to SG-dominated network)	3.0	3.6	96.1	75.3

Line 12 (from Bus 1 to SG-dominated network)	3.0	3.6	96.1	75.3
From Bus 2 to Fault	22.6	21.0	-80.0	-58.4

B. Case 2: A Realistic North American Transmission System

The impact of active current injection by IBRs in a traditional short-circuit model is further demonstrated on a realistic system which consists of following:

- 19 synchronous machine based generating units representing generation capacity of 11 GW; and
- 70 IBRs representing generation capacity of 5.5 GW.

The IBRs are represented using the VCCS model. Three-phase fault currents at six different buses is calculated with IBRs offline and online. The aggregate active power contribution (or absorption) from all 19 synchronous machine based generating units is also compared. When IBRs are online, the negative sign for active power implies that synchronous machines are absorbing active power from the system. Results are noted in Table III. When IBRs are online, the fault current should increase, however, it is not the case as apparent from the results.

TABLE III. FAULT CURRENT AND ACTIVE POWER CONTRIBUTION/ABSORPTION WITH IBRS ONLINE AND OFFLINE.

Bus Voltage				
Fault Location	Total three-phase fault current (A)		Aggregate Active Power (MW) contribution/absorption from synchronous machines	
	IBRs Offline	IBRs Online	IBRs Offline	IBRs Online
Bus #1	21727	19071	422	-1788
Bus #2	8472	7381	324	-3167
Bus #3	8279	6897	301	-3011
Bus #4	8866	7662	358	-3108
Bus #5	9549	8123	347	-2614
Bus #6	6817	5658	229	-2855

As loads are typically not included in the short-circuit model, any active power injected by synchronous machines when IBRs are offline is necessary to support active power losses in the system. For example, all 19 synchronous machine based generating units collectively contribute 422 MWs to the system for a three-phase fault at Bus #1 when IBRs are offline. This contribution is not feeding any loads on the system and simply supplies active power losses on the network occurring due to flow of fault current through the system. However, when IBRs are online, all 19 synchronous machines collectively absorb 1788 MWs of active power. As mentioned before, the VCCS model is configured to inject total current (i.e., combination of active and reactive current) depending on terminal voltage. As such, during a fault condition, IBRs are expected to inject some active power depending on type and location (relative to IBR) of fault. The injected active power by IBRs minus active power losses is absorbed by synchronous machines. The flow of active power from IBRs to synchronous machines causes higher voltage drop through the network resulting in reduced fault current compared to an operating scenario where IBRs are offline.

Table IV shows terminal voltage and current for all synchronous machines for a three-phase fault at Bus #1. When IBRs are online, the voltage at terminals of the synchronous machines is lower compared to when IBRs are online. Also, note how the power factor angle changes when IBRs are online. Negative power factor angle implies terminal current lags terminal voltage. When IBRs are offline, the power factor angle is in range of 85-87°. However, when IBRs are online, power factor angle increases above 90° for all synchronous machines and for some above 100°, implying that each machine is absorbing active power from the system.

TABLE IV. TERMINAL VOLTAGE AND CURRENT OF ALL SYNCHRONOUS MACHINES FOR A THREE-PHASE FAULT AT BUS #1.

Unit #	IBRs offline			IBRs online		
	Voltage (kV)	Current (kA)	PF Angle (deg)	Voltage (kV)	Current (kA)	PF Angle (deg)
SM #1	8.2	7.93	-87	7.36	11.78	-114.9
SM #2	9.4	4.72	-85.1	9.09	6.49	-107.5
SM #3	9.4	4.72	-85.1	9.09	6.49	-107.5
SM #4	10.55	2.77	-85.3	10.05	3.82	-108.9
SM #5	7.42	18.25	-87.5	7.21	19.06	-92.6
SM #6	7.55	17.74	-87	7.35	18.5	-91.8
SM #7	6.73	23.61	-87.6	6.57	24.66	-92.3
SM #8	11.47	18.01	-86.3	10.5	27.54	-115.5
SM #9	11.05	21.14	-86.6	9.9	32.23	-115.3
SM #10	12.67	13.63	-85.2	12.36	16.33	-102
SM #11	12.31	16.34	-86	11.92	19.87	-103.2
SM #12	13.42	11.14	-84.9	13.14	13.34	-101.5
SM #13	12.96	14.39	-85.9	12.57	17.5	-102.9
SM #14	7.29	12.38	-86.6	7.1	12.94	-91.5
SM #15	7.29	12.38	-86.6	7.1	12.94	-91.5
SM #16	7.47	13.35	-86.9	7.1	12.94	-91.5
SM #17	6.21	6.53	-86.7	6.02	7.17	-97.9
SM #18	6.21	6.53	-86.7	6.02	7.17	-98
SM #19	8.2	7.93	-87	7.36	11.78	-114.9

This case study further shows that allowing VCCS model to inject active current (power) in the short circuit model without loads, especially with high penetration of IBRs leads to error in fault current calculations. In this case study it is not possible to determine magnitude of error because of lack of realistic network short circuit model for comparison. In real world, active power injected by IBRs into the transmission network would be absorbed by loads in the vicinity. Additionally, capacitor banks throughout the transmission network would be in-service to support the voltage.

C. Impact of IBR Control

This section studies the impact of IBR control on the short circuit result accuracy issue. Recent grid codes and IBR interconnection standards such as VDE-AR-N 4120 [22] and the IEEE 2800 standard [23] require IBR negative sequence reactive current injection, in addition to positive sequence reactive current injection, during an unbalanced fault. This control typically gives priority to reactive current, meaning that if the total current limit of an IBR is reached, active current needs to be reduced.

IBR negative sequence current injection is expected to have an impact on the accuracy of short circuit results. The reason is that negative sequence current injection further constrains IBR active current output which is the cause of the inaccuracy issue. Essentially, increased negative sequence reactive current injection leads to a smaller active current injection, thus potentially reducing the inaccuracy.

To illustrate the impact, a case study has been conducted on the test system of Fig. 4. A line-to-line fault on Bus 3 has been simulated with and without IBR negative sequence current. Fig. 6 shows the results without negative sequence control. The IBR injects no negative sequence current, and hence the full current capacity is available to positive sequence current. With IBR terminal positive sequence voltage at V1=0.802pu, the injected positive sequence current becomes I1=2.750pu lagging the terminal voltage by -20.8°; the IBR injects an active power of 2.062pu, which is artificially absorbed by synchronous machine SG1.

Fig. 7 shows the results with IBR negative sequence control. In this case, the IBR injects I2=0.413pu which is fully reactive. This current constrains the (positive sequence) active current output due to reactive current priority. Hence, the injected IBR active power reduces to 0.829 pu which is artificially absorbed by SG1. Although the SG still absorbs active power which is unrealistic, the extent of the error has decreased due to a smaller active power injection by IBR.

In conclusion, IBR negative sequence current injection is expected to reduce the extent of the inaccuracy issue due to constrained active current output; however, to what extent in an actual system would depend on fault type and location in the system with respect to IBR(s). This finding applies to unbalanced faults and IBR control compliant with interconnection requirements such as VDE-AR-N 4120 and IEEE 2800 for negative sequence control.

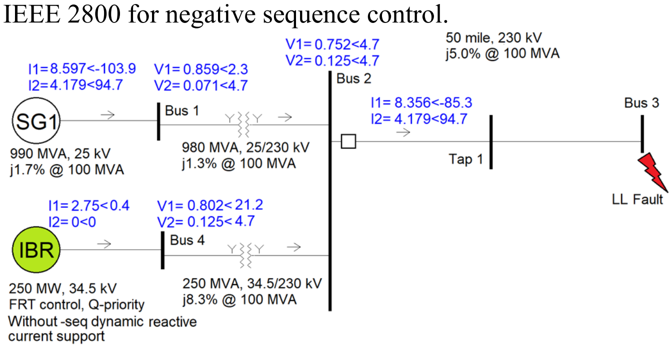

Fig. 6. IBR without negative sequence dynamic reactive current injection.

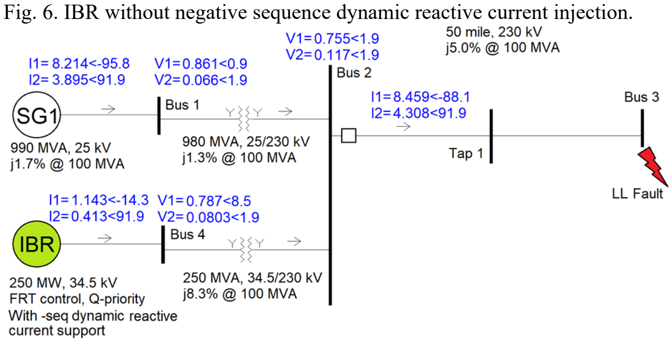

Fig. 7. IBR with negative sequence dynamic reactive current injection.

In summary, lack of load in a short circuit model with IBR may lead to inaccurate simulation results, which could be considerable depending on factors such as IBR integration level, fault type and location, and IBR control. It should be noted that the above-mentioned numerical inaccuracies are not software specific. Further, the IBR short circuit model itself and its implementations within commercial short circuit programs are also realistic. The problem is caused by lack of load model and use of an IBR model which injects active current. These issues may not present a problem for networks with a small amount of IBRs. However, where penetration of IBRs is significant, the extent and impact of such inaccuracies need to be studied, and remedial solutions need to be developed to ensure the fidelity of fault analysis results.

V. Considerations for Improving Simulation Accuracy

This section studies a number of considerations for reducing the identified potential inaccuracies:

- Consideration 1: Modeling all loads;
- Consideration 2: Configuring IBR short circuit model to eliminate active current injection; and
- Consideration 3: Adding artificial load models at IBR point-of-interconnection bus to locally absorb IBR active current injection.

The effectiveness of these considerations has been studied through simulation case studies performed on a model of a 16,436-bus North American transmission test system, shown in Fig. 8. In this system the IBRs are concentrated in the Northern part, whereas loads are mainly centered in the Southern part with a few load pockets in other locations including within the IBR region. IBRs have been represented by the VCCS tabular model [17] which represents active current injection. This model is same as one shown in Table I.

A distant fault to IBR location has been simulated, and short circuit results have been compared under the above-mentioned considerations. Fig. 9 presents the amplitude and phase angle of positive sequence voltage (V1) and positive sequence current (I1) phasors of selected buses and lines close to the IBR region and the corresponding error. Modeling all loads (Consideration 1) presents a realistic scenario and hence has been chosen as reference. The figure highlights cases with a large error (e.g., an error in amplitude larger than 10% or an error in phase angle larger than 10 degrees).

A. No Load Model

This case represents the classical assumption of ignoring load model in short circuit studies. The results have been marked by "No Load Modeled" in Fig. 9. As shown, the following result inaccuracies occur:

- SGs on Bus 2 and Bus 15 absorb 0.55 pu and 0.10 pu active power, respectively, which is unrealistic; and
- The calculated amplitude and phase angle of line currents become inaccurate. The largest current amplitude error is about 13% (corresponding to I1 from Bus 2 to Bus 3), and the error is about 10% in a few other cases. The largest current phase angle error is 26° (corresponding to I1 from Bus 2 to Bus 3), and the error is around 20° in a few other cases.

The results further substantiate the conclusion that lack of load model may lead to inaccurate short circuit results under IBRs.

While this consideration is expected to provide accurate results, it may not be practical. A reason is that load modeling typically requires creating realistic generator dispatch scenarios for the power-flow simulation to converge; this can require a significant resource to establish and maintain. Hence, any added value obtained by modeling loads may be outweighed by the challenges of creating and maintaining load model.

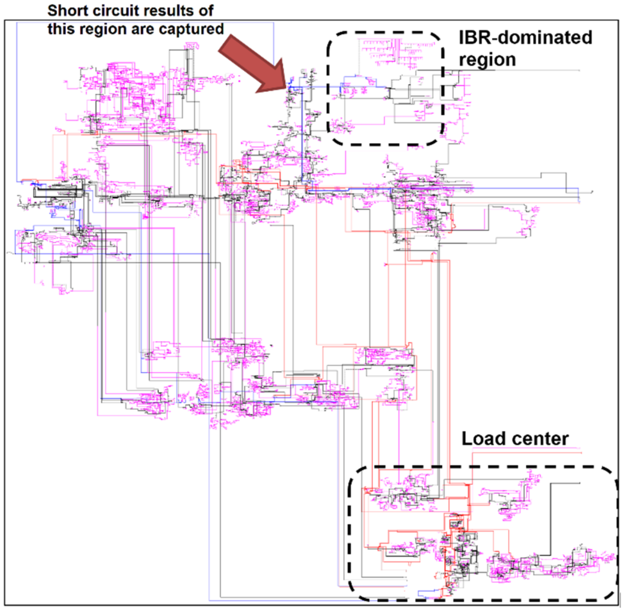

Fig. 8. The transmission test system.

Another consideration would be to model only those loads which are located within the IBR region, if any such loads exist. These local loads are expected to partially absorb active current injection from IBRs, thus improving accuracy to some extent. The applicability of this consideration depends on the presence of local loads within the IBR region. This is not typically the case, since in an actual power system load centers are located far away from IBR locations, as with the test system of Fig. 8.

In summary, while including load models in transmission short circuit model is expected to improve accuracy, it may not be a practical option.

B. Consideration 2: Configuring IBR short circuit model to eliminate active current injection

This consideration is based on reprogramming IBR short circuit model to eliminate IBR active current injection. This can be implemented, for example, by entering zero in the Active Current column of Table I (i.e., entering -90° in the PF Angle column).

The results have been marked by "Consideration 2: No IBR MW." The results suggest that this consideration does not improve accuracy, and in a few cases the error is even further increased compared to the case with no load model. The reason is that while the IBR-injected current no longer contains an active component, the amplitude of the injected current may no longer be realistic due to the neglected active current component. This may lead to inaccurate calculation of inverter terminal voltage which in turn reduces the accuracy of the injected reactive current component. Hence, the effectiveness of this approach in improving accuracy needs to be further studied.

C. Consideration 3: Adding artificial load model

Under this method, artificial loads are added at individual IBR terminals to locally absorb their injected active current. Such loads can be designed based on the following considerations:

- The load power factor is set at unity since the objective is to absorb IBR active current component only;
- The load rated power consumption is based on the rating of the corresponding IBR. This ensures that at about 1 pu inverter terminal voltage where the IBR is injecting close to 1 pu active current, the artificial load is also absorbing close to 1 pu active current.
- The load type is constant-impedance type to reduce the active power consumption of the load with decreasing terminal voltage, where the IBR contributes less active current.

The results have been denoted by "Consideration 3: Artificial Load." The accuracy has not been improved. The reason is that the absorption of IBR active current by the artificial load changes the amplitude of the overall injected fault current, thus leading to inaccurate calculation of inverter terminal voltage.

It should be noted that the artificial load method may improve accuracy in cases where the actual transmission network includes loads in close vicinity of IBRs. This is a limitation since typically load centers are far from IBR locations, in which case the artificial load method may not improve accuracy.

VI. Conclusions

This paper has studied the impact of load modeling on fault analysis of IBR dominated grids. Traditionally, the short circuit model of large-scale transmission grid does not include loads. On the other hand, state-of-the-art IBR short circuit models call for injection of active current component. In the absence of load model, this active current circulates in the transmission network, thus potentially skewing the amplitude and phase angle of short circuit voltages and currents. The paper has identified such potential inaccuracies and provided considerations to reduce the error and improve fidelity of short circuit results in IBR dominated grids.

The main takeaways of the paper are:

- Lack of load in short circuit models with IBRs may lead to inaccurate results. The inaccuracy mainly manifests in two forms: (i) active power absorption by SG models which is not realistic; (ii) skewed amplitude and phase angle of short circuit voltages and currents.
- The inaccuracy is more significant when fault is distant to IBRs and active current component in current injected by IBR is high.

The paper has further examined the effectiveness of the following considerations in improving accuracy and evaluated their practical limitations:

- A consideration is to include load in short circuit models. While this consideration is expected to provide accuracy, it may not be practical due to the challenges of creating and maintaining load model in short circuit models;
- Another consideration is to re-parameterize the IBR model to eliminate the active current component. In the conducted simulation of this paper, this consideration did not improve accuracy; and

- Another consideration is to put artificial loads at IBR model terminals to locally absorb the injected active current injection. This consideration may not improve accuracy in networks where load is located far away from IBRs.

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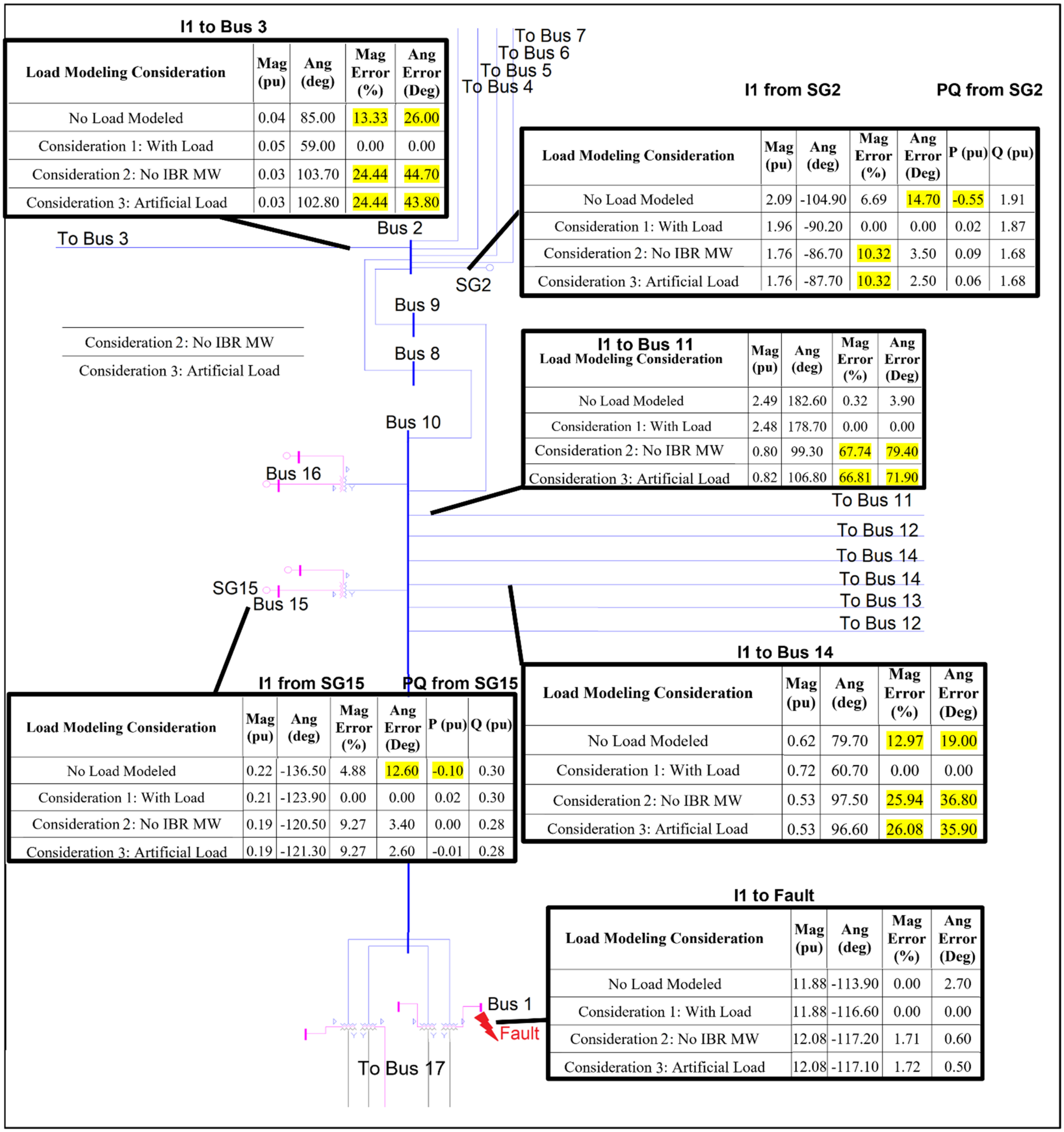

I1 to Bus 3

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)
No Load Modeled	0.04	85.00	13.33	26.00
Consideration 1: With Load	0.05	59.00	0.00	0.00
Consideration 2: No IBR MW	0.03	103.70	24.44	44.70
Consideration 3: Artificial Load	0.03	102.80	24.44	43.80

I1 from SG2 / PQ from SG2

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)	P (pu)	Q (pu)
No Load Modeled	2.09	-104.90	6.69	14.70	-0.55	1.91
Consideration 1: With Load	1.96	-90.20	0.00	0.00	0.02	1.87
Consideration 2: No IBR MW	1.76	-86.70	10.32	3.50	0.09	1.68
Consideration 3: Artificial Load	1.76	-87.70	10.32	2.50	0.06	1.68

I1 to Bus 11

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)
No Load Modeled	2.49	182.60	0.32	3.90
Consideration 1: With Load	2.48	178.70	0.00	0.00
Consideration 2: No IBR MW	0.80	99.30	67.74	79.40
Consideration 3: Artificial Load	0.82	106.80	66.81	71.90

I1 to Bus 14

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)
No Load Modeled	0.62	79.70	12.97	19.00
Consideration 1: With Load	0.72	60.70	0.00	0.00
Consideration 2: No IBR MW	0.53	97.50	25.94	36.80
Consideration 3: Artificial Load	0.53	96.60	26.08	35.90

I1 from SG15 / PQ from SG15

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)	P (pu)	Q (pu)
No Load Modeled	0.22	-136.50	4.88	12.60	-0.10	0.30
Consideration 1: With Load	0.21	-123.90	0.00	0.00	0.02	0.30
Consideration 2: No IBR MW	0.19	-120.50	9.27	3.40	0.00	0.28
Consideration 3: Artificial Load	0.19	-121.30	9.27	2.60	-0.01	0.28

I1 to Fault

Load Modeling Consideration	Mag (pu)	Ang (deg)	Mag Error (%)	Ang Error (Deg)
No Load Modeled	11.88	-113.90	0.00	2.70
Consideration 1: With Load	11.88	-116.60	0.00	0.00
Consideration 2: No IBR MW	12.08	-117.20	1.71	0.60
Consideration 3: Artificial Load	12.08	-117.10	1.72	0.50

Fig. 9. Comparison of fault analysis results under various load modeling considerations.