SIEMENS

Inverter-Based Generator Models with Controlled Power and Current: 2020 CAPE User Guide

2020 PSS®CAPE UGM

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2020 PSS®CAPE User Guide

I. Introduction

The PSS®CAPE Short-Circuit Program includes wind or solar generators, which are examples of "Inverter-Based Generation" (IBG). The model predicts the limited current from the controller under a sudden external disturbance or fault. PSS®CAPE uses the computed currents to set relays, check coordination, and check breaker ratings.

Steady-state phasor models have been developed at the Electric Power Research Institute and Polytechnique Montréal [1,2,3], and coded in CAPE by Siemens:

- "Type IV" generators with a full power converter between the input source and the network,

- a basic "Type III" model which is a synchronous generator with a limited current.

- a Voltage-Controlled Current Source (VCSS) in which the current and power factor are given functions of the bus voltage. The postfault currents are supplied in current-voltage tables for actual type III or IV generator. These tables have been derived outside CAPE from detailed electromechanical transient simulations, [3], or have been supplied directly from IBG manufacturers.

Sections II and III explain the EPRI Type IV model. The steady-state solution does not always exist. Section IV shows how CAPE treats a non-converging voltage. Section V explains how to enter data for Types III, IV, and VCSS.

This user guide updates the Application Note presented at the 2019 CAPE UGM [4]. Appendix A summarizes the changes made since 2019.


II. Type-IV Generator

A. Description

Figure 1shows one Type-IV wind turbine or solar panel connected to the grid. It represents an aggregate model with all wind turbines in parallel and a single LV-MV transformer and collector. PGC is the point of generator connection (low voltage – e.g. 0.6 kV) and POI is the point of interconnection of the plants at transmission level (e.g. 120 kV).
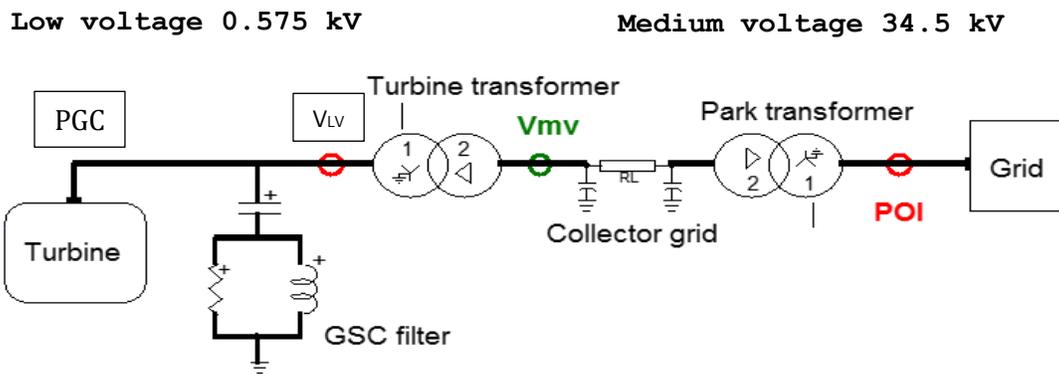
(a) Wind turbine
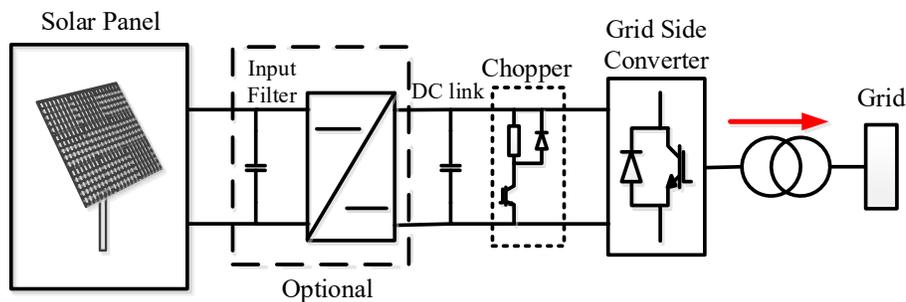
b) Solar photovoltaic with DC source

Figure 1: Inverter-Based Resource (EPRI).

The response to a sudden disturbance (network fault) is governed by the controller, which sets the bus voltage or reactive power and limits the current. The proportional or proportional-integral regulators are modeled using an iterative solution of steady-state equations. In the model the currents are the controlled response to a constant power source at the network frequency after the initial transient: about 2 cycles after the fault.

The EPRI and CAPE models treat the generator between the Grid Side Converter (GSC) (at low voltage, LV) and the wind-park MV/HV transformer. The controls are applied to the currents and voltages at the point marked "V_{LV}" (low voltage) in Figure 2.1), and the network bus is at the V_{MV} (medium voltage) point. CAPE controls and limits the fault current (I_d, I_q) in a reference frame rotating with the voltage V_{LV}.   Neutral currents are suppressed. The IBG differs from a synchronous generator, which CAPE Short-Circuit treats as a linear device with a constant internal EMF) in series with a constant shunt impedance (subtransient or transient.

The turbine transformer in Figure 1 is a two-winding wye-delta transformer (typically 0.575 kV/34.5 kV). It is part of the generator model and is not a separate transformer in the CAPE database. It has a single series impedance (default $0.01 + j\,0.1$ per unit on generator base), for positive- sequence quantities only. The Park transformer from V_{MV} to POI (e.g. 34.5kV/120kV) is modeled separately, using an N-Circuit model in the database.
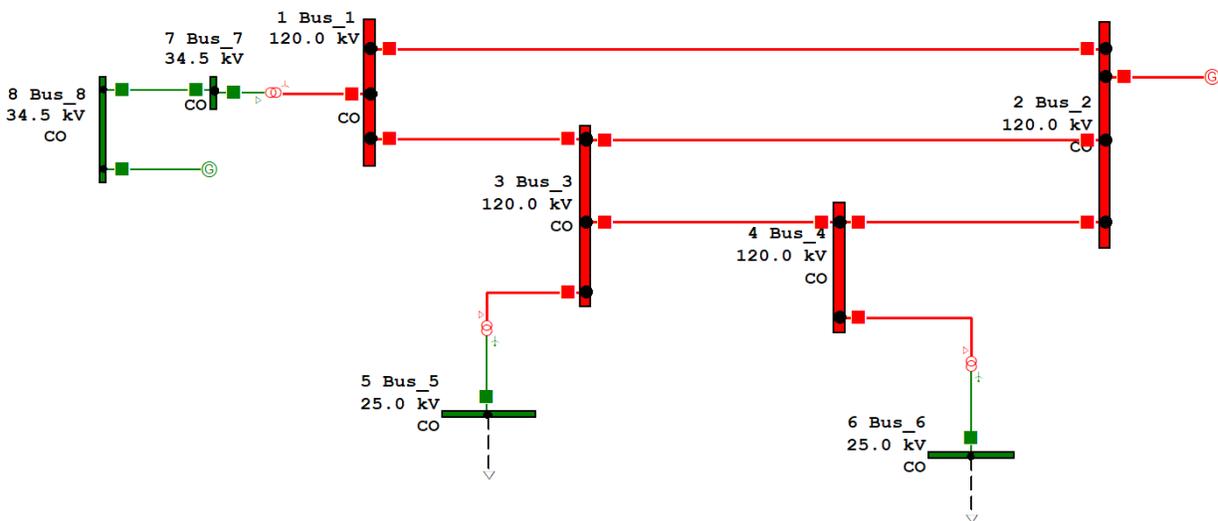
Figure 2 shows the 9-bus test case.

Figure 2: Nine-bus test case with one solar generator at bus 8.

For numerical solutions, see [4].

B.   Initial Conditions with a Power-Flow Solution.

CAPE Power Flow (PF) uses the Unit Output (P, Q) from the Power-Flow-Data at the IBG bus as the target solution. CAPE PF does not solve the IBG. The IBGs are evaluated in the CAPE Short-Circuit (SC) algorithm when you apply a fault.   The IBG currents are expected to be different from the power-flow solution because the IBG and Power Flow calculation are different.

To view the prefault voltages and currents, apply a "No fault condition" in CAPE SC. With Use_Voltage_Profile OFF, the bus report shows zero currents. If the user has run CAPE PF and Use_Voltage_Profile is ON, CAPE shows the Power Flow solution without an applied fault.   If the voltage profile is not accurate, CAPE SC will report a Prefault Mismatch.   To exclude the mismatches, set "Reported_Currents Incremental" and "Relay_Currents Incremental"

III.   Current Control in Type-IV Generators

Controls and current limits are applied to the voltage $V_{LV} = V_{PGC}$ and current I_{PGC} in the "d-q" plane, at the grid-side converter.   The d-q components are DC quantities in a reference frame following the peak positive-sequence voltage (V_p perunit), so V_q is always zero. In practice, a phase-locked loop (PLL) keeps V_d and V_p synchronized.

CAPE uses the following algorithm to calculate the steady-state current (I_d, I_q) from the generator to the network, subject to the chosen power, the current limits and the controls of voltage or reactive power.

- Within each iteration, loop through all the current-limited generators in the system.

- For the first iteration, use the prefault bus voltages, which may consist of a load-flow profile or a classical flat profile at 1.0 perunit.   Derive the prefault current (I_d, I_q) from the specified reference power (P, Q).

- For subsequent iterations, inject the controlled currents from all generators into the network and apply the chosen fault in the MV system to obtain the incremental network voltages, [5]. The total bus voltage is obtained from the IBG solution at an IBG bus or by adding the prefault voltage at other buses.

- Remove any generators isolated from the network by open breakers or by a solid three-phase fault.

- Start testing for convergence after 4 iterations. For each generator, find the difference in positive-sequence bus voltage at the MV bus, $|V_p^{(k)} - V_p^{(k-1)}|$ in iteration (k).   If the voltage difference exceeds the tolerance, the voltage for that generator has not yet converged.   The default tolerance is MXI_ITER_TOL = 0.01 pu on the system base MVA.

- For all IBG types (III, IV, or VCCS): if the iterated voltage has not converged after 30 iterations (settable), continue for up to 30 more iterations, in which the injected current lags the voltage by 90 degrees.   The current magnitude is increased to its limit (III and IV) or the value in the table for the voltage (VCCS).

- Compute the positive-sequence voltage and current (V_p, I_p) at the LV grid-side converter.

The following transformations relate the LV and MV voltages and currents:

Phasor Conversion from MV to PGC across filter and wind-park transformer

Node PGC is the output of the converter on the grid side of the turbine, at low voltage LV, where the controls are applied. MV is the medium voltage winding of the turbine transformer where current is injected into the network. Current I_P from the generator into the network is defined to be forward when it leads or lags the generator voltage Vp by 0 to 90 degrees.

In perunit:
Yfilter = shunt admittance
ZTransformer = series leakage impedance

V_{LV} = V_{MV} + ZTransformer * I_{MV}
I_{LV} = I_{MV}
VPGC = V_{LV}
IPGC = I_{LV} + YFilter * V_{LV}

Phasor Conversion from PGC to MV across filter and wind-park transformer

V_{LV} = VPGC
I_{LV} = IPGC - YFilter * V_{LV}
I_{MV} = I_{LV}
V_{MV} = V_{LV} - ZTransformer * I_{MV}

- Convert (V_p, I_p) to d-q values as in the panel below. V_d is a DC voltage synchronized with the rotating voltage V_p.

```
Transformation from positive-sequence values to d-q values
using LV voltage as a reference phasor

Vd = abs (Vp)
Vq = 0

Angle arg(Vp) is saved for the inverse transformation

The prefault power (P + jQ) determines the initial direct current in the
rotating reference frame:

Id = P/Vd;    Iq = -Q/Vd

P + jQ = Vd * (Id - j Iq ) = Vp * Conjg(Ip)

In terms of positive-sequence phasors,
P = | Vp * Ip| cos(θ)
Q = | Vp * Ip| sin(θ)
where θ = Power-Factor Angle = phase lead of voltage Vp from current Ip.

A phase-locked loop (PLL) keeps Vd equal to the magnitude of the positive-
sequence phasor voltage so that the out-of-phase voltage Vq is zero.
All phasor magnitudes are RMS values.
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The first iteration sets the "d" current component of current, which is in phase with the voltage.

$$I_d = P/ |V_p| = P / V_d$$

Subsequently, this current will be subject to the chosen limits.

The desired reactive current $\hat{I}_q$ is derived in each iteration by applying steady-state controls to the latest solution (V_p, I_p) at the MV node. (Here, the "^" symbol marks a desired value, also known as a "target" or "reference" value.)

The user specifies one of the following control types:

1. Q control, injecting reactive current $\hat{I}_q = -Q/abs(V_d)$ at the PGC node. $\hat{I}_q$ is the current before applying limits. Q is a fixed "reference" or "target" reactive power, supplied in the machine data. By convention, $\hat{I}_q$ is negative when Q is positive, delivering reactive power from the generator to the grid.

2. Power-factor control. Given the desired power factor PF, an equivalent Q is derived from the real power P and used for Q control:

$$\cos(\theta) = \text{Specified power factor}$$
$$Q = P * \tan(\theta)$$

By convention, if PF is entered as a negative number, angle θ is between − 90 degrees and 0; otherwise θ is between 0 and 90.

3. V control. The desired Q is computed to keep abs (V_p) constant at a specified reference value (e.g. 0.97 pu).

4. FRT control (fault ride-through), adding reactive current from the generator into the network.

$$I_q = - K_{FRT} *(1 - abs(V_d{}^{(k)}))$$

K_{FRT} is the chosen slope (dI/dV). The default value is 2 per unit on the machine MVA and bus kV bases.   The region of zero current in the Fault Ride-Through I-V characteristic has been removed from the EPRI model and from CAPE: now the I-V slope is continuous with a non-zero current limit at all voltages.

5. WP controller mode similar to FRT, with the prefault voltage and reactive current $I_{qg}{}^{(0)}$ as target values.   This option is no longer in use; use FRT instead.

The program obtains the current (I_d, I_q) at the PGC node and applies limits to the current components I_d, I_q and the magnitude (Figure 3). The user chooses priority for P (I_d) or Q (I_q). The current component with higher priority is allowed to have its maximum value, while the lower-priority current may be limited below its maximum.   Normally, control modes Q and PF use P priority; modes V, FRT and WP use Q priority to maintain bus voltage.
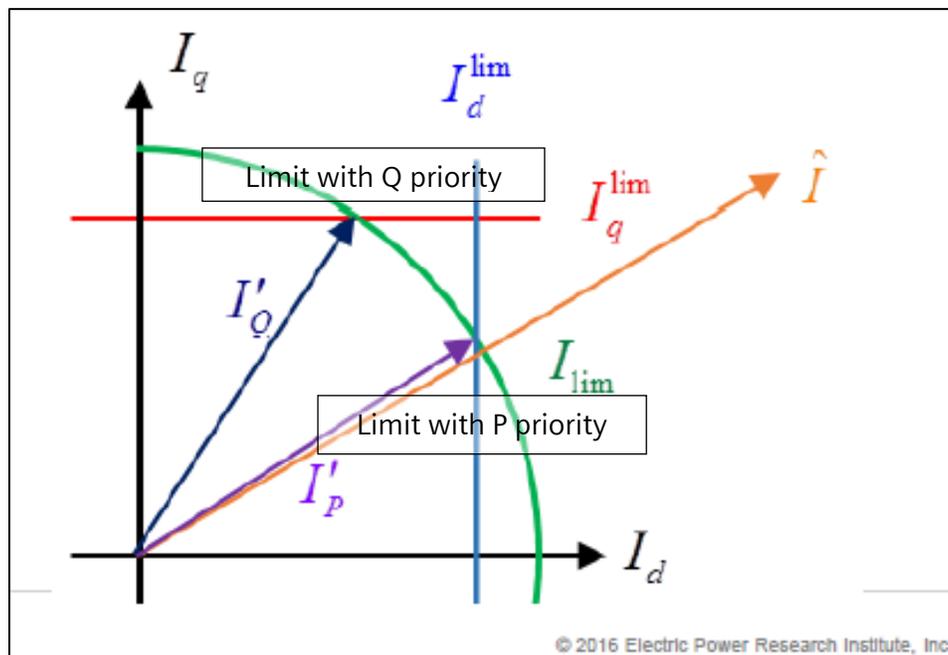

Figure 3: Current Limits for d and q components of desired phasor Î (from EPRI)

With P control priority, reduce I_d with constant I_q, then reduce Î, and finally reduce I_q.

With Q control priority, reduce I_q with constant I_d, then reduce $\hat{I}$, and finally reduce I_d.

If the I limit is entirely outside the limits of I_q and I_d, the I limit (green circle) is ignored.

If the I limit is entirely inside these limits, the angle of $\hat{I}$ is retained and the I_d and I_q limits (red and blue) are ignored. The following steps are used:

- Convert the limited current (I_d, I_q) to positive-sequence LV current I_p.

> The inverse transformation from currents (I_d, I_q) is applied at the PGC node:
>
> $I_p = (I_d + jI_q) * \exp j(\arg(V_p))$
>
> Here V_p is the +seq voltage phasor saved from the start of this iteration. Arg(V_p) is the phase angle of the short-circuit voltage at the start of the present iteration. This angle is relative to a fixed phasor 1.0 @0 degrees. It can include a prefault multiple of 30 degrees due to Y-Delta transformers.

- Transform the current phasor I_p to the MV winding bus for the next network solution.

- For each generator, inject its current I_p into the external faulted network.

- With all currents injected simultaneously, compute the postfault system voltage V_p at the generator buses.

Repeat these steps. If not all generator voltages have converged at MXI_ITER iterations (default 30), switch the non-convergent generators to "Iq-injection". In the "Iq_injection" state, the GSC active current is zero and the reference reactive current is set at its limit:

$$I_{dg}^{(k)} = 0$$
$$I_{qg}^{(k)} = -I_q^{lim}$$

Continue for a further MXI_ITER iterations.

Every generator voltage is recomputed until all the generators in the network have converged. If one or more WTGs still have not converged after the second set of MXI_ITER iterations (e.g. Iteration 60), the WTGs which did not converge are disconnected (placed in "Disconnected" state) with zero MV current. Then new voltages are computed. The process is repeated for the remaining generators.

IV.   Convergence (Types III, IV or VCCS)

When the solution for positive-sequence current I_p has converged, CAPE injects the current Ip into the network to compute a network voltage V_p. You can apply other faults simultaneously. Ip

and Vp are the _total_ current and voltage at the generator bus with prefault and postfault quantities combined (non-linearly) by the iterative solution.

In terms of power at the MV bus:

$$V_p * Conjg(I_p) = \text{ controlled power } (P + j\,Q) \tag{4.1}$$

Figure 4 shows a portion of the 2015 Southern Company network with a solar generation plant connected in one substation. There is infeed from regular synchronous generators between the solar generator and the fault.   These synchronous generators provide balancing current to the solar generators.
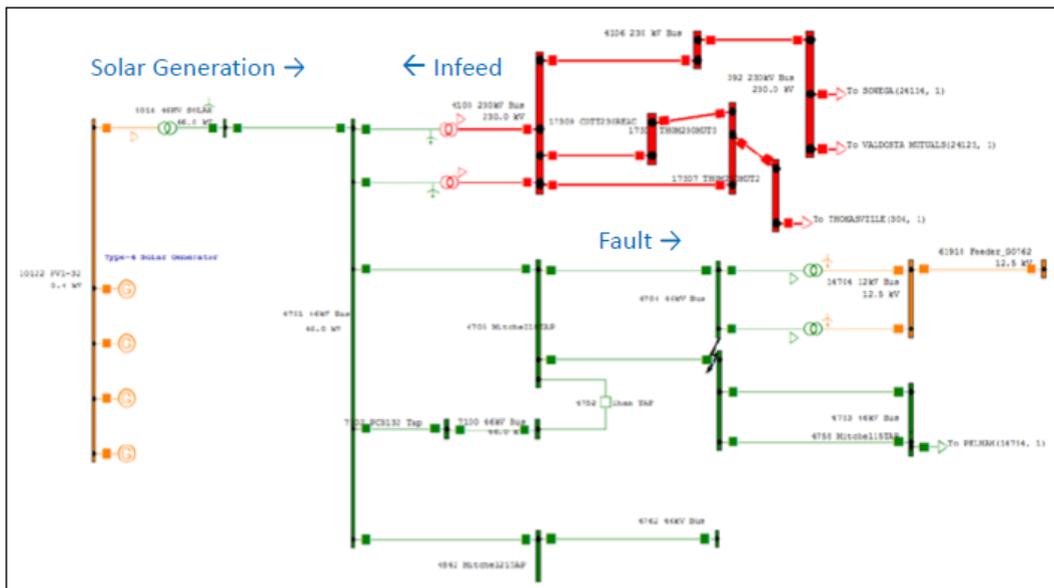

Figure 4: Portion of Faulted Southern Company Network with Solar Generation. The arrows indicate the flow of real power after the fault.

If there is no source of infeed current between the generator and the fault, the iterative solution may not converge.   Then the power-flow angle from the generator to the network cannot be determined. This is a real situation, with loss of synchronism between the network and the generator, causing changes of frequency. There is a limited range of phase angle arg (Ip/Vp) allowing power transmission, [6]. The extreme case is a solid fault on a radial line, where no power is transferred to the network.

If the controls cannot produce a current consistent with the faulted network, the computed postfault voltage after any iteration repeatedly leads or lags the voltage in successive steps. This happens, for example, when the generator is "islanded" by a low-impedance three-phase fault, with no other source of current between the generator and the fault.

CAPE tests the two sides of Equation 4.1 and reports the difference in angles:

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***   Not converged after 60 steps with variable angle arg(Vp/Ip)

Controlled power at MV

Power delivered =  P + jQ = Vd * (Id – j Iq)
Vp*Conjg(Ip) MVA at MV           19.241    14.621    24.166 @  37.2; P_Factor  0.796
Vd * (Id – jIq) at MV            28.572    -7.059    29.431 @ -13.9; P_Factor  0.971
Mismatch at MV                   -9.330    21.680;   Angle mismatch (deg) 51.11

Controlled power at PGC(LV)

Vp*conjg(Ip) MVA at PGC (LV)     20.036    21.420    29.330 @  46.9; P_Factor  0.683
Vd * (Id – jIq) at PGC (LV)      29.322    -0.702    29.330 @  -1.4; P_Factor  1.000
Mismatch at PGC                  -9.286    22.122;   Angle mismatch (deg) 48.28
```

The techniques described below were suggested by EPRI, to produce convergence in marginal cases.

1. At the start, CAPE, searches the unfaulted network for a path from each inverter-based generator to a synchronous generator. If the IBG is isolated from all synchronous generators, the IBG is removed from the solution.   This situation may occur temporarily while a breaker is open to clear a fault between the generator and the transmission network.

2. CAPE detects a solid three-phase fault and removes the generator when the initial postfault voltage (+seq) at the IBG bus is below 0.0001 per unit (allowing for numerical error in the step-up transformer).

    Since the voltage phase angle is undefined at the zero-voltage bus, the computed current has no fixed reference angle: it can take any value relative to the network and may produce misleading network current. This situation arises for type IV and type VCCS. For type III, the synchronous-generator model produces a non-zero voltage unless the fault is on the IBG bus.

3. The changes of phase angle arg (I_p) at successive iterations are smoothed (made smaller) by interpolating the value.

4. The apparent impedance Z_p at the MV bus is computed with the fault applied in the network.   If Z_p is constant in the first three iterations, the generator is considered to be islanded by the fault. Then CAPE keeps the voltage angle arg (V_p) at its prefault value in Equation 4.1, so the controls and current limits are applied in a fixed (d-q) reference frame.

    The network voltage angle arg (V_p) and the ratio I_q/I_d now converge separately, leaving a mismatch angle β between the input and output currents at the generator bus. Equivalently, the solution contains fictitious mismatch current and power at the bus. This current must have been generated by the controller, although the EPRI / CAPE algorithm does not model it.

5. If the solution has not converged in MXI_ITER_N iterations, the generator currents that did not converge are switched to an "Iq-injection" state, for a further MXI_ITER_N iterations. Here $I_d = 0$ and $I_q = -I_q^{lim}$ at the LV node; the injected current I_p lags the voltage V_p by 90 degrees at the LV node. At the MV bus, real power flows backwards from the network into the MV/LV transformer because of the transformer load loss.

6. If the voltage still fails to converge, the shunt is removed temporarily while other generators operate.

To see the details of the iterations, right-click on the generator symbol in the One-Line diagram, or on Short-Circuit Shortcuts, and choose Wind/Solar Generation and Report IBG. You must have set MXI_VERBOSE ON (in cape.cfg) to allow CAPE to save its results in a work file. Setting MXI_VERBOSE OFF make the solution faster but does not keep the iteration details.

V.   Adding a Controlled Generator to the CAPE Database

A user carries out the following steps.

A.   Set Current Limits ON

To include the controlled generators, you must first set "Use Current Limit" as "Both_On" in the Global tab of Short Circuit Preferences (Figure 5). Or use the command-line shortcuts:

CLIM OFF
CLIM ON

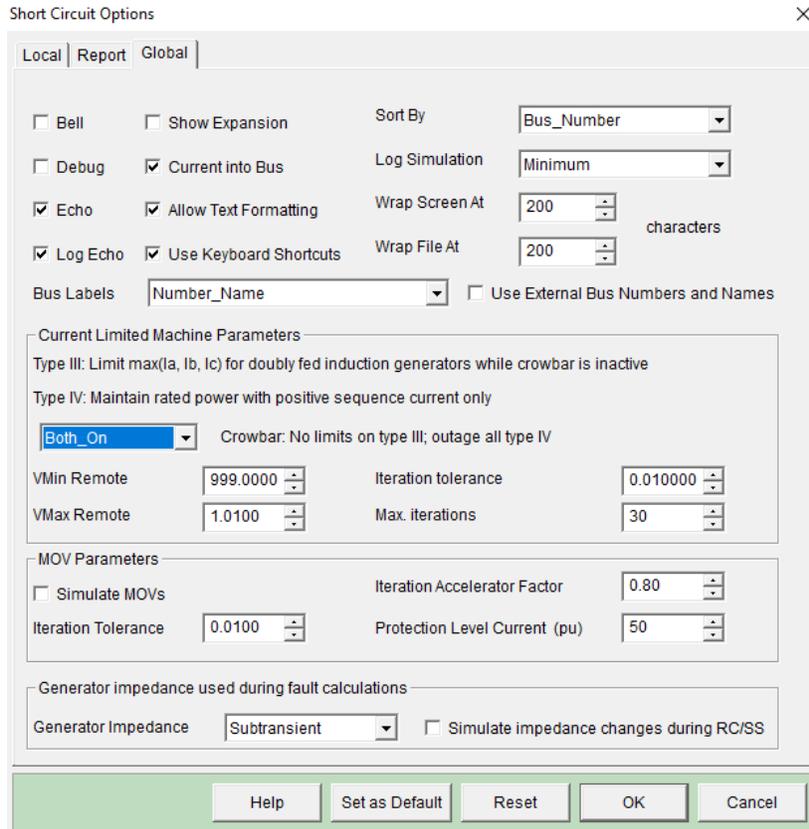CAPE rebuilds the network whenever you change this setting.

Figure 5: Setting CAPE to Study WTG and PV Generators (all types).

In addition, any generators can be included or excluded using the equipment categories for the network.

To list the existing generators, open the Short-Circuit Shortcuts menu, and choose "Wind/Solar Generation" and "Report All IBGs".

B.   Place the Generator

Choose the substation and bus on the database search forms; add a shunt of type "Generator" or copy an existing shunt (Figure 6).
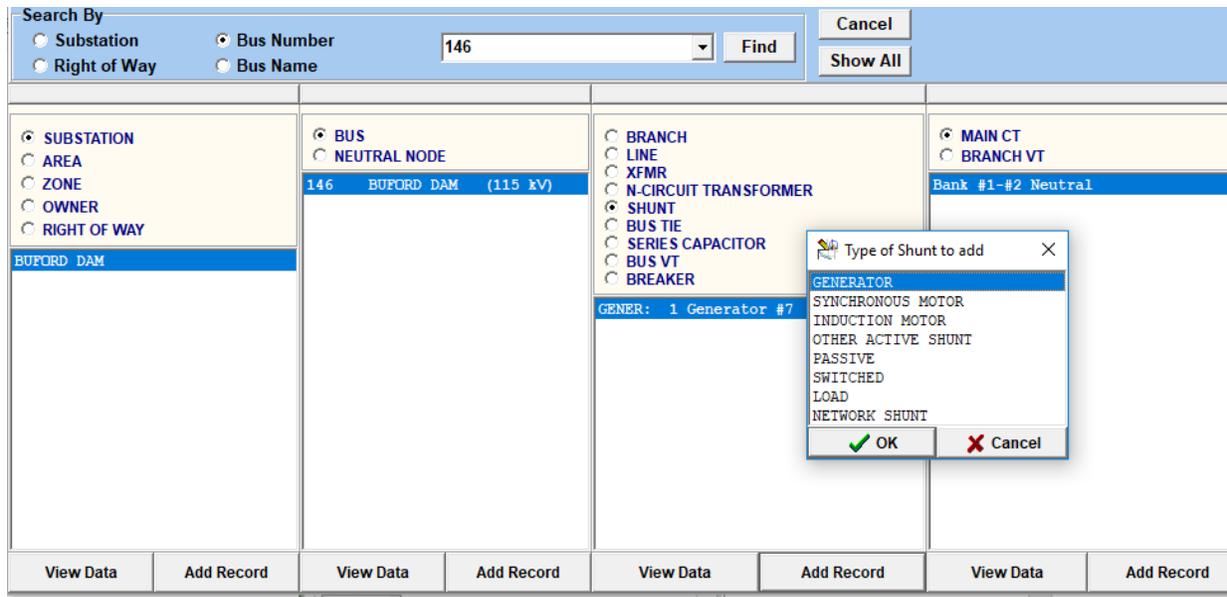
Figure 6: Adding a Machine using the Database Forms.

Alternatively, use a One-Line Diagram: display the Drawing Toolbar; then double-left-click on the G icon and drag it to the generator bus on the diagram.

C.   Add Generator Data

For each generator, all the data is on the Generator Data form and its menu tabs (Figure 7).
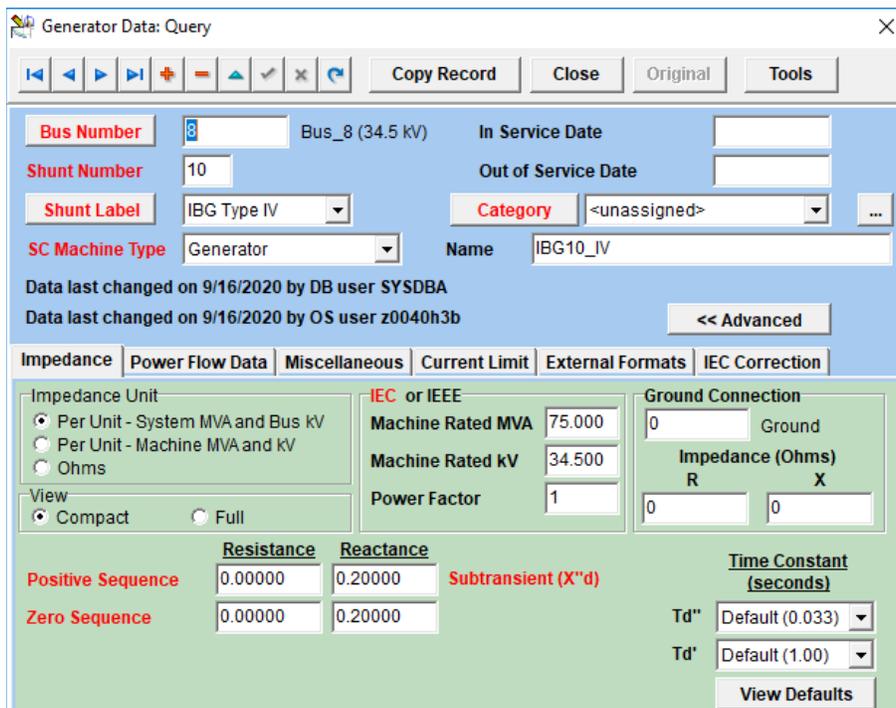

Figure 7: Generator Data with Current Limit Tab.

Enter the Machine Rated MVA and Rated KV as bases for the per unit impedances for synchronous or type III generators on this form.   The MVA is the Apparent Power |P+jQ|.   For Machine Rated kV, enter the bus base (line-line kV).   Ignore the Power Factor on this form, because the iterative solution recalculates it.

The System MVA is generally different because it applies globally as a common base for the network calculations (such as 100 MVA).

If you intend to run Power Flow together with CAPE SC IBG, you should also enter the desired (P,Q) in the Power Flow data, in the fields MW and MVAR Unit Output" (Figure 8).   The Power Flow solution treats P and Q as constant and saves the non-flat prefault voltage profile in the database. In CAPE Short-Circuit, the IBG model reads the voltage profile if you choose the Setup Option "With Load Currents". At buses with IBGs, the IBG voltage replaces the power-flow voltage.

Figure 8: Power-Flow settings at a bus with IBGs. This Power Flow solution uses Machine Type "Fixed MW and MVAR" with (P, Q) =67 MW and 33 MVAR. With a flat voltage profile, you can ignore this form.

Ignore the ground connection, since zero-sequence currents are removed from all IBG types (III, IV, or VCCS).   CAPE automatically sets a zero-sequence reactance of 9999.0 per unit for the generator. These generators are usually connected to MV delta windings on the MV-HV transformer.

Negative-sequence currents are automatically included in Type III for unbalanced faults, since the type III model is just a synchronous generator with a limited current. When the current is limited, the proportions of the postfault phase (A, B, C) currents are fixed. Types IV and VCCS deliver positive-sequence quantities only.

After reading the database, Build_SC_Network converts all currents and powers to per unit on the System MVA and local bus base kV for the fault calculations and reports.

At present, you may ignore the Time Constants.

For a controlled generator, choose Current Limit (Figure 9)

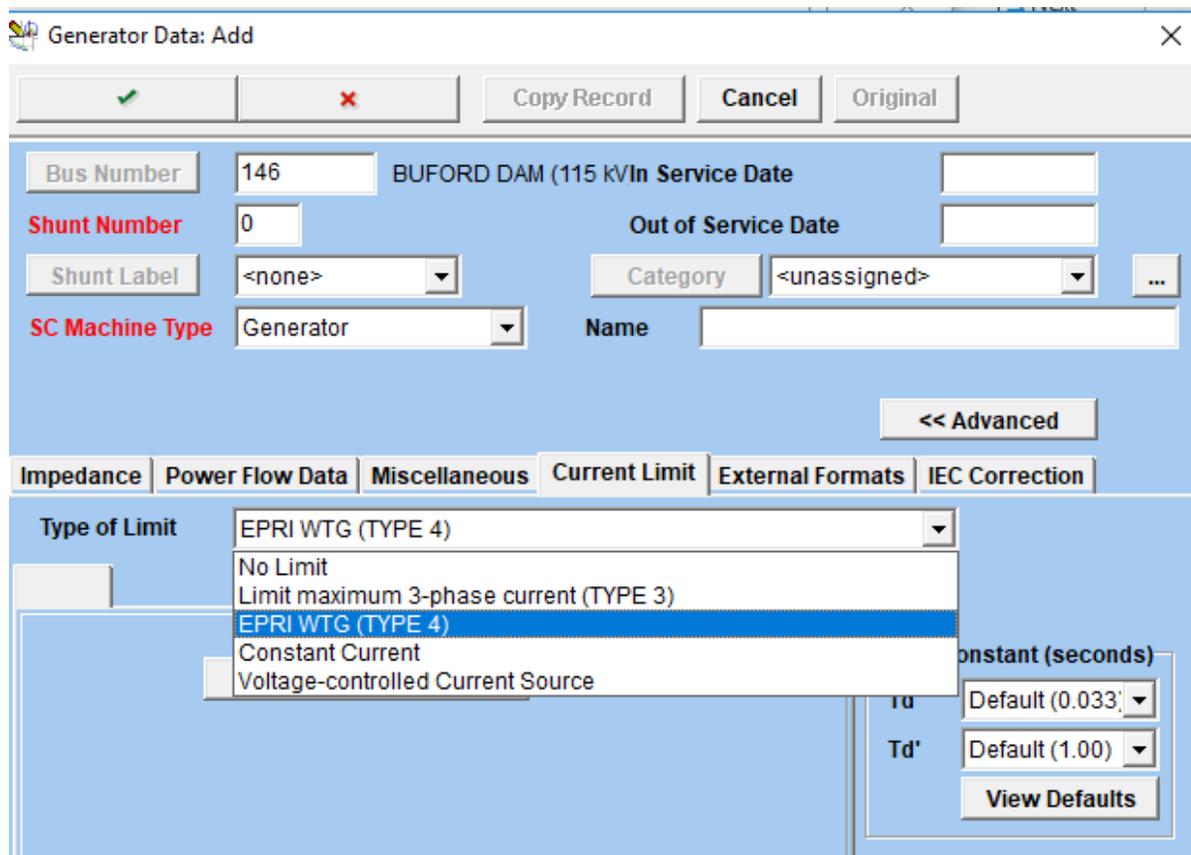### D.   Set the Current Control

Figure 9: Types of Controlled Generator.

The options for Current Limit are:

- <u>No Limit</u>: conventional synchronous generator with specified impedances.

- Limit maximum 3-phase current (TYPE 3): If the largest postfault phase current is below the limit this model behaves as a synchronous generator with the specified impedances for + and – sequences. The current limit is independent of the voltage.   In the absence of a more detailed model, the proportions of the phase currents are fixed when the current is limited.   Zero-sequence current is suppressed because the transformers should have delta secondary windings.
- EPRI Type 4 (IV): the EPRI full-power converter described above.
- Type VCCS: voltage-controlled current source.   The VCCS type allows a manufacturer to supply the current-voltage characteristic directly for types III or IV, without disclosing details of the controller.

E.   Enter Data: TYPE IV IBG

Figure 10 and Figure 11 show the **TYPE IV** Power Converter Data form. Set the "Enter Data Using" field first to either "Total MVA of turbines", (Figure 10) or "System Base MVA" (Figure 11).

Figure 10: EPRI Power Converter Parameters in CAPE with Turbine MVA chosen.

Figure 11: Power Converter Parameters with "Enter Data Using" changed from Turbine MVA to System MVA. The per unit values change, while the physical values are not changed.

The values on the form are follows:

1.   Turbine Parameters

Turbine Type
Only FC (Type IV Full Converter) is allowed for Type IV at present

Number of Turbines
Specify one or more turbines, which CAPE will combine in parallel and model as a single shunt at the bus. You may also place two or more separate shunts at the same bus, with different Shunt Numbers. These shunts should have the same type of control and equal current limits and power ratings.

After reading the database, CAPE computes the total power as (Power S per turbine) * (Number of turbines).

If a generator has 2 turbines at 10 MVA each, for example, S=10 and the Machine MVA is 20.0. This equals the total three-phase MVA of the turbines. The total Machine MVA is used as the base for per unit power. The base amps is (MVA*1000)/($\sqrt{3}$* Low voltage line-line base kV) with MVA = 2 * S = 20.

S
Nominal apparent power (MVA) of one turbine. The power base (reference power) for this generator is set as:

Machine MVA = (Number of turbines) * (S for one turbine)

Because S is used as a base power, it is helpful to choose S to make the default per unit values realistic.   These values include characteristic slope, target voltage or reactive power, current limits, and the transformer or filter impedances.   If this information is not be given in the manufacturer's specifications, instead you can use generic values, such as a current limit of 1.1 pu.

P
Prefault real power generation (MVA) directed from one turbine to the grid.

P and Q are the initial powers used in the iterations. They do not have to add (vectorially) up to S. They determine the initial prefault current and prefault voltage at the MV and LV nodes. The iterative solution will recompute new values. You may leave P and Q as zero or supply nonzero P and Q in combination on the form with a flat prefault voltage profile or a load-flow profile. To start with all bus voltages at 1.0 perunit, choose "Classical Short Circuit" under Session Setup.

Q
Prefault reactive power generation (MVA) directed from one turbine to the grid.

Q and P have the same sign when P is positive, and the voltage leads the prefault current by an angle θ between 0 and 90 degrees.   If the current leads the voltage by 0 to 90 degrees, P and Q have opposite signs.   Angle θ is the prefault Power Factor Angle, which is $\tan^{-1}$ (Q/P), or 0.0 if P and Q are both zero.

V
Base (reference) line-line voltage for perunit quantities, in kV at the generator bus.
Normally this is equal to the bus base kV, so the reference voltage is 1.0 perunit on the system base. The bus is on the MV side of the turbine transformer.

2.   Control Parameters

Voltage Control: Location (not in use)
PGC only
Location where the voltage is controlled: PGC or POI, where PGC (or PCC) is the point of generator connection at the low voltage (LV) and POI is the point of current injection. The present model applies the controls at the PGC only and injects the current into the network at the POI (MV bus)

Control Location: PGC or POI (not in use)
PGC only
This choice allows the controlled voltage and the controlled current to be at different voltages. CAPE uses only PGC.

Control Mode
Specify the quantity to control: voltage (V), reactive power (Q), power factor (PF), or fault ride-through (FRT).   The wind-park controller option WP is no longer used.

Slope: (FRT only)
The slope (dI/dV) pu is defined as (Change of current I_q)/(Change of voltage V_d) on the linear operating characteristic of the grid-side converter. A slope of 2.0 is typical (in perunit on machine base and low-voltage bus kV)

Deadband Vpu (not in use)
The FRT constraint is applied only where the voltage V_d is outside the deadband Min Vpu $\leq$ $V_d \leq$ Max Vpu on the system base.   Set values of 1.0 to remove the deadband.

Control Priority
The priority P or Q applies to the current limits for I_d, I_q and their vector sum.
With P priority, I_d is limited first; with Q priority I_q is limited first. For V, FRT or WP control, choose Q priority to maintain bus voltage. For Q or PF, choose P priority for maximum real power.

PGC Control: Desired bus voltage (pu) (V control and FRT only)
Enter the desired voltage V_d perunit (default 1.0). This is used for V control and is the target voltage for fault ride-through.

Desired reactive power generation (pu) (Q control only).
Enter the desired reactive power generation in multiples of the chosen base MVA. A positive value injects lagging current into the network.   This value is distinct from the prefault reactive power Q listed above. Q control injects reactive current $\hat{I}_q = -Q/abs(V_d)$ at the PGC node. $\hat{I}_q$ is the current before applying limits.   Q is a fixed "reference" reactive power, supplied in the machine data table. By convention, $\hat{I}_q$ is negative when Q is positive, delivering reactive power from the generator to the grid.

GSC Current Limiter

Enter the three perunit limits, I-Limit, Id-Limit, and Iq-Limit, for currents |Id + jIq|, Id, and Iq.
If you change the base (S), the per-unit limits will change, keeping the amps constant.

3.   Network Data

LV-MV Transformer

This models the aggregate turbine/inverter transformer for Type IV models. A two-winding
three-phase transformer converts the inverter low voltage to the collector system medium
voltage. The turns ratio is the ratio of MV and LV line-line voltages (bus base kVs).

Set the leakage impedance (R, X) = (0.01, 0.1) perunit or use the actual value. Magnetizing
(excitation) shunt admittance is ignored, since the 0-sequence current is suppressed and the
+seq shunt impedance is much higher than the leakage impedance.

The load loss reduces the power delivered to the network and makes the delivered power
negative if the controlled power is set to be purely reactive on the LV side.

 You can add one or more external transformers using the CAPE N-Circuit model with MV
secondary winding and transmission-voltage primary winding.   The external transformer may
include a delta tertiary.

If you also need to model the LV-MV transformer separately, set the internal impedance (R, X) as
zero and use the following steps:

- Add a real bus at the GSC (LV) voltage.
- Use the database editor (shunt data) to reconnect the IBG (which was at the MV bus) to
  the LV bus just added.
- Then add an external transformer from the new bus to bus 8 (LV to MV delta-Y with the
  delta on the LV winding).
- Copy the existing leakage impedances from the IBG to the newly added transformer.
- Then set the IBG internal impedance as zero.
- Leave the rest of the external network (at the MV bus) unchanged.

> **Network ----- MV bus -------New XFMR -------- New LV Bus ---- IBG with series impedance set as zero**
>
> **IBG Connections with External MV-LV transformer**

This method allows you to connect more than 1 generator to a common wind-park
transformer at the LV bus.

Filter Admittance

The filter is a capacitive shunt. Set G = 0 and B = 0.01 per unit on the chosen MVA base or use
the actual value.

MVA Base Selection
Use "Total MVA of Turbines" for per unit settings close to 1.0.   You can see the same physical values on the system base by choosing "System Base MVA".

Internally, CAPE converts all currents and powers to per unit on the system MVA base (e.g. 100 MVA, three-phase) and then stores them in the database.

F.   Data for Type III with a fixed current limit.

Type III uses the impedance on the generic form together with the current limit, rated MVA and bus kV (). The shunt impedance and EMF are constant for currents up to the limit, as in a synchronous generator or with crowbar type III operation.

Since this is a generic approximation for Type III, you can enter zero for the negative-sequence impedance and use the +seq impedance as the default. Alternatively, make the negative-sequence impedance infinite (1.0E8 is high enough).
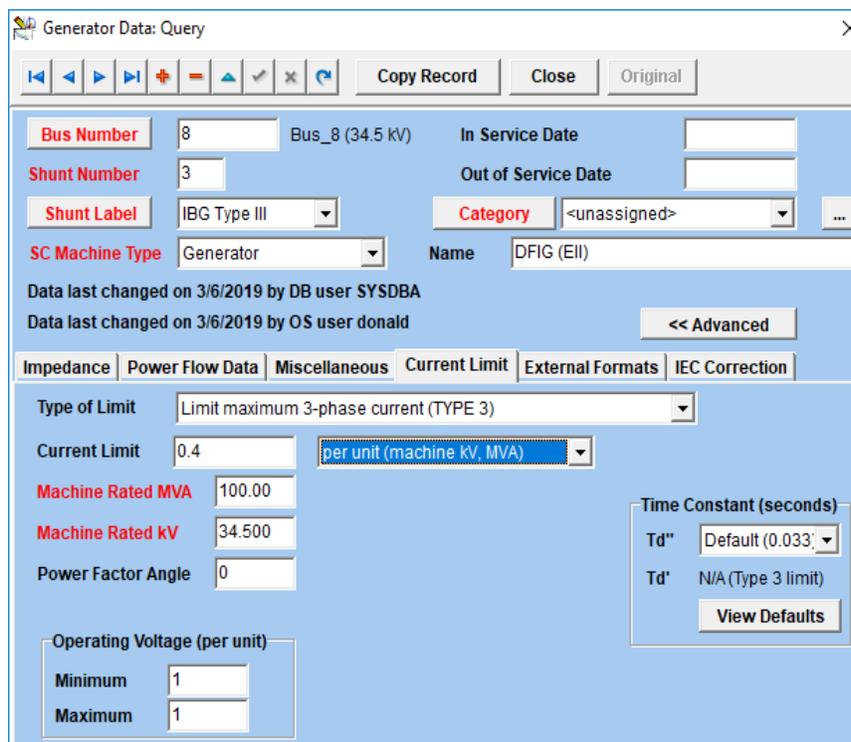
Add Impedance data

Figure 12: Type III Current Limit.

G.   Data for Voltage-Controlled Current Source: Type VCCS

Voltage-Controlled Current Source (VCCS):

Here the current and power factor are given functions of the bus voltage. In this model, the generator voltage at the network (MV bus) determines the current and power-factor angle via

tables of values. Only positive-sequence values are used. CAPE suppresses the negative-sequence current for all faults, although negative-sequence tables are given in [3].   The zero sequence currents are removed by the Delta-Wye MV transformer.

In the Generator Data, leave the Ground Connection zero. CAPE will also ignore the resistance and reactance fields and will ignore the Power Factor, using the table instead. Under Current Limit, choose the VCCS option. Enter the data in Table 1 into Figure 13 or use the default values. If there are fewer than 10 values, enter a zero in the voltage column to end the table.

Table 1: Voltage-controlled Current Source.

Voltage (pu)	d-axis current (pu)	q-axis current (pu)	total current (pu)	Power factor angle
1.000	1.000	0.000	1.000	0.00
0.900	1.000	-0.200	1.020	-11.31
0.700	0.922	-0.600	1.100	-33.06
0.500	0.458	-1.000	1.100	-65.38
0.300	0.458	-1.000	1.100	-65.38
0.100	0.458	-1.000	1.100	-90.00

Figure 13: Tabulated data for VCCS from [3] (10,000 base amps,100 MVA and 0.575 kV).

These points specify the current generated for any fault. For a range of bus voltages, the VCCS table contains the positive-sequence current in amps and the power factor angle arg(Ip/Vp). This angle is the phase lead of positive-sequence current Ip from the bus voltage Vp. For reactive current injection, Ip lags Vp, so arg (Ip/Vp) is a negative number. The current is lowest for a remote fault with 1.0 pu voltage at the generator.

H.   Controls set by the user

These settings have priority over controls and current limits for Types III and IV and have priority over the tables for Type VCCS.

Set the following parameters, either temporarily on the Global Short-Circuit Preferences form, or permanently in the users' configuration file "|CapeUserDir|\cape.cfg"   These values are global and apply to all the controlled generators in the network.

MXI_ITER <value>
 (or CURRENT_LIMIT_ITER <value>)

Number of iterations before switching non-convergent generators to "Iq-injection". Default 20. If the initial iterations do not converge, a second loop with fixed voltage angle is used for a further MXI_ITER iterations**.**

E.g. MXI_ITER 30

MXI_ITER_TOL <value>
Largest change in voltage magnitude per iteration (V_{pu}) allowed for convergence. Default 0.01 per unit on bus base kV.

If the solution converges, but the bus report shows an excessive mismatch current, increase MXI_ITER to 30 or reduce MXI_ITER_TOL by a factor of 10.

VMIN_REMOTE<value> (Type IV only)
VMAX_REMOTE<value> (Type IV only

This option lets CAPE removes generator currents due to a remote fault. For a given faulted bus, CAPE will ignore the generator if the generator bus voltage is close to its prefault value, specifically if **VMIN_REMOTE** $< V_{pu} <$ **VMAX_REMOTE**.

Typical values are $0.95 < V_{pu} < 1.1$.   These limits suppress current that would actually be dissipated in nearby loads.   To keep all generators, set VMIN_REMOTE = 999. This option adds the generated current and tends to raise the fault-arc current at external faults.

VMIN_IBG (not in use)

Largest voltage (pu) to be treated as isolating the generator for a nearby three-phase fault Default: **VMIN_IBG** = 0.01

Option VMIN_IBG is no longer used (since September 2019). It is replaced by a fixed limit of 0.0001 pu.

VI.   Reports.

These reports help a user to understand how the controlled generators respond to a fault.

A.   Bus Report

Figure 14 shows a CAPE bus report with the IBG shunt "IBG TYPE IV".

```
Line Removal "3 Bus_3"  to  "2 Bus_2" Ckt 1 at Sub3
Midline node on "1 Bus_1"  to  "3 Bus_3" Ckt 1 at 0.090
THREE_PHASE at temporary bus "999001 Bus_1" (NEWBUS1)
-----------------------------------------------------------------------
Substation Sub1
Bus  8 Bus_8  CO  Base kV   34.50 Ph-Ph (   19.92 @-30 deg A-Gnd)
Prefault 1.000 V (p.u.)   @  -30.00
+ seq             - seq           0 seq / 3Io
--------------   --------------   --------------
Voltage (p.u.)      > 0.17349 @ -44.0   0.00000 @   0.0   0.00000 @   0.0
Voltage (kV) Ph-Gnd > 3.45560 @ -44.0   0.00000 @   0.0   0.00000 @   0.0

Shunt Currents (Amps) incremental (I) and total (T) from >
IBG Type IV      I 1 1290.15 @-130.7   0.00002 @ 156.2   0.00005 @   0.0
IBG Type IV      T 1 1290.15 @-130.7   0.00002 @ 156.2   0.00005 @   0.0
Total of  46 steps needed for all IBGs
8  1 Type IV      45 iters; Iq at limit   0.77@-130.7 pu on sys MVA;

Line Currents (Amps) incremental from >
Sub1  Line:  COLLECTOR
7 Bus_7          1 1290.15 @  49.3   0.00000 @   0.0   0.00000 @   0.0
```

Figure 14: Bus fault report for generator bus. This solution took MXI_ITER = 30 steps without converging and then switched to Iq injection at the limit of 0.77 pu on the system base.   The Report_IBG command provides these details.

B.   Report_IBG

For a detailed report of a single generator, right-click on the generator symbol on the One-Line diagram, or use the Short Circuit Shortcuts menu (Figure 15):
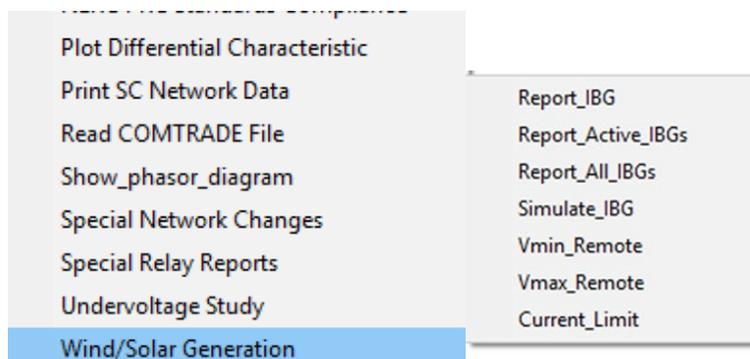

Figure 15: Short-Circuit Shortcuts Menu.

Alternatively, on the command line, specify the generator bus and circuit numbers:

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report_ibg (<generator bus>, <circuit_number>)

Example: REPORT_IBG (8, 10)

Figure 16 is an excerpt for the case above.

```
Line Removal "3 Bus_3"  to  "2 Bus_2" Ckt 1 at Sub3
Midline node on "1 Bus_1"  to  "3 Bus_3" Ckt 1 at 0.090
THREE_PHASE at temporary bus "999001 Bus_1" (NEWBUS1)

CONTROL MODE        FRT Fault Ride Through
CONTROL PRIORITY    Q

 Loop Iter Bus CCT   VP_MV pu  mag,deg    Ip@MV pu      P,Q MVA       P,Q Mismatch  del MAG
  1    0    8   1   1.00 @  -30.0    0.68 @  -30.0  67.51     0.00    0.00   0.00    0.00
  1    1    8   1   0.18 @   57.0    1.01 @  -16.6   5.25    17.87   -4.73   2.81    0.19
  1    2    8   1   0.16 @   49.8    0.85 @  -21.9   4.16    12.57   -4.11   1.39    0.03
  1    3    8   1   0.15 @   58.6    0.84 @  -12.9   4.03    12.04   -4.03   1.35    0.02
  1    4    8   1   0.15 @   67.6    0.84 @   -4.0   3.85    11.63   -4.03   1.34    ...
  1    5    8   1   0.14 @   77.2    0.84 @    5.0   3.62    11.25   -4.09   1.35
....

  1   28    8   1   0.16 @   41.6    0.84 @  -30.4   4.19    12.90   -4.22   1.41
  1   29    8   1   0.16 @   50.2    0.84 @  -21.4   4.14    12.45   -4.09   1.38
  1   30    8   1   0.15 @   58.9    0.84 @  -12.6   4.02    12.03   -4.03   1.35    ...
  2    1    8   1   0.15 @   43.0    0.77 @  -27.8   3.70    10.61    4.49  -0.53
  2    2    8   1   0.15 @   32.9    0.77 @  -38.7   3.68    11.06    4.47  -0.52
....

  2   14    8   1   0.17 @  -40.9    0.77 @ -126.9   0.93    13.37    1.73  -0.07    0.01
  2   15    8   1   0.17 @  -44.0    0.77 @ -130.7   0.77    13.35    1.56  -0.06    0.01
  2   16    8   1   0.17 @  -44.0    0.77 @ -130.7   0.77    13.35    1.56  -0.06    0.00
```

Figure 16: Convergence report. In this case the real power after convergence is only 0.77 MVA and the voltage has fallen from 1.0 to 0.17 pu, because the desired current was not attained. After 30 iterations (MXI_ITER) the control was switched to reactive current injection with current Iq fixed at its limit. The voltage was allowed to vary. The solution converged in a further 15 iterations. The current Ip (0.77 pu A @ -131°) lags the voltage Vp (0.17 pu @ -44°) by 87°.

C.   Report_all_controlled_generators (Report_Active_IBGs)

This report (Figure 17) is obtained via the SC Shortcuts menu (Wind and Solar Generation).

```
 Summary of controlled generation
      Bus … Shunt #              P,Q MVA       Status
    1 24xxx   1  Type IV …    1.16,   81.67  Iq injection at current limit
    2 96…     1  Type IV      0.00,    0.00  Remote fault
    3 88      1  Type IV      1.13,   80.91  Iq injection at current limit
    4 84      1  Type IV      0.00,    0.00  Remote fault
   ...
   81 11      1  Type III     0.00,    0.00  Remote fault
   82 11      1  Type III     0.00,    0.00  Remote fault
   85 72      1  Type III     0.00,   22.50  Radial line (islanded)
   86 11      1  Type III    34.99,   14.37  Converged in 6 iterations
   ...
  113 11      1  Type IV      0.00,   83.22  Iq injection at current limit
  114 11      1  Type IV    100.87,   41.55  Converged in 6 iterations
```

Figure 17: Excerpt from summary for 114 IBGs.

This report demonstrates multiple IBGs in a large network, showing which generators are active at a bus or substation. "Remote fault" implies a postfault voltage close to 1.0. With more than 30 iterations, the model has switched to Iq injection.

D.   Macro "Simulate_IBG"

This macro tests for convergence. It applies three-phase faults at a chosen bus with varied fault-arc resistance. A plot of the output power or bus voltage at one generator shows whether the solution converges.

VII. Conclusions

The CAPE and EPRI programs compute a voltage-controlled current from an inverter-based generator. EPRI and Polytechnique Montréal have provided single-generator solutions, but a program such as CAPE with its user interface and database is needed for large-scale studies on an actual network. The steady-state phasor model applies to both wind and solar generators, because the controllers are similar. The steady-state algorithm solves simultaneous equations for the faulted network with controlled current and voltage at one or more generators. If there is no steady-state solution, the generator is removed and identified in the reports.   Dynamic solutions with EMTP-type programs show the evolution of a fault over time, but they are impracticable for wide-area fault studies because of their complexity.

The next tasks in CAPE are to implement the detailed EPRI Type III and IV models with controlled current, to make a more realistic model. For Type III we will first add the positive-sequence controls described in [7], and then add (optional) controls for negative-sequence currents. After Type III controls are working satisfactorily, we will include negative-sequence controls in type IV [8] Further development depends on customer experience. In particular, several users would like guidance on choosing the current limits from the available manufacturer data, instead of choosing the defaults.

References

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[6] Goksu, O.; Teodorescu, R.; Bak, C.L.; Iov, F.; Kjaer, P.C., "Instability of Wind Turbine Converters During Current Injection to Low Voltage Grid Faults and PLL Frequency Based Stability.

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[8] Thomas Kauffmann, Ulas Karaagac, Ilhan Kocar, Simon Jensen, Evangelos Farantatos, Aboutaleb Haddadi, and Jean Mahseredjian, "Short-Circuit Model for Type-IV Wind Turbine Generators with Decoupled Sequence Control," IEEE Transactions on Power Delivery, Vol. 34, No. 5, pp 1998-2007; October 2019.

Appendix A: Updates – October 2020

- The three IBG types modeled in CAPE are:

  Type IV: Full-Power Conversion including controls (+sequence only)

  Type III: Doubly-Fed Induction Generator, treated as a synchronous generator with a current limit

  VCCS: Voltage Controlled Current Source with a user-supplied table of voltage, current and power factor.   These models do not include negative-sequence controls.

  The generator rated MVA per turbine appears on both the Generator Data form and the Current Limit forms.   In case the values are different, CAPE always uses the value from the Current Limit form.

  "CLIM TYPE_3_CROWBAR" treats Type III as a synchronous generator without a current limit and excludes Types IV and VCCS.

- For all IBG types (III, IV, or VCCS): If the iterated voltage has not converged after 30 iterations (settable), CAPE runs up to 30 more iterations in which the injected current lags the voltage by 90 degrees.   The current magnitude is the limit (III and IV) or the value in the table for the voltage (VCCS).

- Zero-sequence currents are removed from all IBG types (III, IV, or VCCS)

- CAPE detects a solid three-phase fault and removes the generator when the initial postfault voltage (+seq) at the IBG bus is zero (within a tolerance of 10^{-4} per unit).

- To rebuild the network with IBGs included, you may enter the shortcut "CLIM ON" on the command line. "CLIM OFF" excludes all the IBGs.

- The defaults for the iterations are set in the Short Circuit Preferences as

  MXI_ITER_TOL   0.01 (unchanged)
  Current_Limit_Iter 30 (increased from 20 to improve convergence)

- For the Voltage-Controlled-Current-Source (VCCS) model, the injected current, the phase angle arg (I/V) and the column heading in the report have been corrected.

- The optional deadband from Vmin_Remote to Vmax_Remote now applies to Type IV generators only

Updates – June 2019

- EPRI control options V, Q, FRT and Power Factor (PF) apply to Type IV model

- Fault Ride Through (FRT) control is now a separate option; previously it followed a solution with V or Q control.

- Report_Active_IBGs summarizes the power output from multiple generators.

- Type III has a set current limit.

- Type III crowbar option treats all Type III generators as synchronous (no current limit).

- Voltage-Controlled Current Source (VCCS) is added with constant current as a special case.