ABSTRACT

For availability reasons, many generating utilities keep custom designed spare transformers in storage, readily available and identical to their critical large power transformers. However, in case the exact replacement is not possible, the only option the generating utility has is to search for a substitute transformer that, as a minimum, is able to offer a temporary solution. The purpose of this paper is to indicate the most important aspects to be considered when checking the interchangeability of such substitute transformer, based on authors' experience and on various standards requirements.

Keywords:

power plants, power transformers, interchangeability.

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Issues to Consider when Substituting Large Power Transformers in Generating Stations

INTRODUCTION

The power transformer is a reliable device, yet not failure-free. It has no rotating parts and consequently, no typical faults of rotating machines. On the other hand, the large transformers are oil-immersed and suffer from other faults, mainly chemically or electrically related. A transformer internal fault may be very difficult to locate and repair. In many cases, the owner may decide that it is faster and cheaper to buy a new transformer than to repair an old damaged one. Even when the repair is worthwhile, it may last for many months.

Almost all large transformers used in power plants are custom-designed. Keeping suitable spare transformers in storage is a common practice for the purpose of avoiding long unplanned outages and high economic losses. In case the exact replacement is not available, the only option the generating utility has is to search for a substitute transformer that, as a minimum, is able to offer a temporary solution that may introduce some operational constraints. The goal of this paper is to mention the most important aspects to be considered when checking the interchangeability of such substitute transformer. The discussion is based on the various requirements included in the relevant American and European standards.

If a power transformer in a critical condition fails and an identical spare one is not available, the generating utility will search for a substitute transformer as a minimum temporary solution.

The most common generating station arrangements are shown in Fig. 1: a unit generator-transformer block configuration, and a unit generator-transformer with generator breaker. The vital large transformers in a power plant are the unit step-up/main/generator transformer (UT), the auxiliary transformer (UAT) and the station service/reserve transformer (SST). A failure of any one of these transformers may lead to unit shutdown or start-up unavailability.

GENERAL LAYOUT

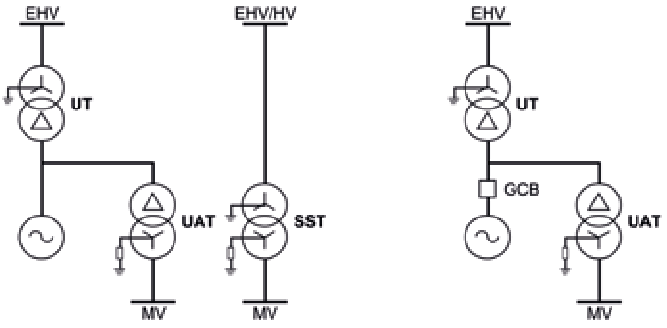
The UT may consist of a single three-phase unit, two half-size three-phase units or three single-phase units. This is the most evident aspect to consider when a substitute transformer is needed. When designing a new plant, the selection among these alternatives is generally based on consideration of some form of strategic reserve as well as the available space. Two half-size transformers may be selected in place of a single full-size transformer in order to reduce the cost of the spare. For similar reasons, a generator transformer may be turned into a bank of single-phase units. Normally the cost, mass, and loss of such solutions are larger than for a single three-phase transformer; however, they may be preferable if transport size or weight limits apply. The three single-phase transformers provide independent magnetic circuits (see Section XI below), representing high magnetising impedance for zero-sequence voltage components. Therefore, a delta equaliser winding is normally provided, implemented by the external connection between the phase units.

Some layouts may further complicate the spare transformer availability, like the UAT with three-winding design.

DIMENSIONS AND WEIGHT

Any physical size and weight limitations should be checked, for example for installation on an existing foundation. Special installation space restrictions may influence the insulation clearances and terminal locations on the transformer.

UT and UAT are connected to the generator through isolated phase bus ducts. The high/extra high voltage terminals of the UT may be connected to gas insulated switchgear. The medium voltage connections to the plant auxiliaries are also normally done via the rigid, non-segregated phase bus bars or cables. All these aspects must be checked and solved when looking for a transformer replacement.



a) Unit generator-transformer
b) Unit generator-transformer block configuration with generator breaker

RATED FREQUENCY

In an unlikely situation of considering a transformer designed for a different frequency, the following applies. The rated frequency radically affects the transformer design and operation. The general formula of voltage e induced by a variable flux φ in a coil with N turns is $e = -N\,d\varphi/dt$. Assuming a sinusoidal flux $\varphi = \Phi m \cos \omega t$, the induced voltage becomes $e = \omega N \Phi m \sin \omega t$. Its rms value will be, in terms of core cross section A and flux density Bm [1]:

$$E = 2\pi/\sqrt{2}\, f\, N\, \Phi m = 4.44\, f\, N\, A\, Bm. \qquad (1)$$

According to (1), in case a transformer designed for 60 Hz needs to operate at 50 Hz, means that the same voltage can be achieved only by a substantial increase in the flux density. The core iron will become heavily saturated, the excitation current will rise as well as the hysteresis losses (proportional to the area of the hysteresis loop), which could severely overheat and damage the laminations.

When a transformer designed for 50 Hz operates at 60 Hz, there is too much iron in the core. The hysteresis losses will be higher than the 50 Hz designed value (because of iron volume and increased frequency), thus decreasing the efficiency. More importantly, the eddy currents losses will heat up the laminations because they tend to increase as the square of the frequency. Operation of a 50 Hz rated transformer at 60 Hz may be possible sometimes but its nameplate MVA rating [2] may have to be derated, depending on the new versus rated voltage.

MVA RATING

The substitute transformer rated MVA is obviously a first parameter to consider. When a new plant is designed, the UT rating is chosen to ensure that it will not represent a bottleneck of unit capability under any possible operating condition. However, a substitute UT poses a different perspective: using a smaller MVA rating than the original one means generating unit derating, nevertheless it is normally preferable to a complete shut-down taking into consideration the long time needed to obtain the exact replacement.

> **If rated power of a substitute transformer is lower than the one of the original transformer, its suitability is checked according to the standards and operating restrictions which may apply.**

In the case of a transformer (especially UT) substitution, it is essential to pay attention to the differences among the various standards about the definition of rated power. The IEC 60076-1 [3] definition implies that the rated MVA is the apparent input power, received when rated voltage is applied to the primary winding and rated current flows through the terminals of the secondary winding; the output power is principally the rated power minus the power consumption in the transformer (active and reactive losses). On the other hand, by the North America conventions (IEEE C57.12.80 [4]), the rated MVA is the output power that can be delivered at rated secondary voltage.

If the transformer nameplate mentions a certain rated power and if it was designed to conform to the American standards, the significance is that its primary (connected to the generator) would be able to receive higher than the rated power. If for instance, the UT impedance is 15%, it should be able to accept a primary MVA up to 15% higher than the rated one, including the load and magnetising losses (in the worst conditions of lagging power factors). The exact values can be obtained by using the equivalent circuit of the transformer. Contrarily, such intrinsic capability will not be available in a transformer exhibiting the same rated MVA but designed to the IEC requirements. The situation inverts under the leading power factors (Mvar absorbed from the system) but this is a less likely regime, especially when a substitute transformer is involved.

A transformer may be able to carry loads under some limitations in excess of the nameplate rating. In a case of a substitute transformer, the expected regime is a long-time emergency loading that may persist for months. Both IEEE and IEC have standards specially dedicated to such loading aspects (IEC 60076-7 [5], IEEE C57.91 [6]). The application of a load in excess of the nameplate rating involves accelerated ageing and risk of premature failure, for instance: deterioration of conductor insulation, and other insulation parts and oil at high temperatures; overheating of metallic parts; increased gassing in the oil; high stresses in the bushings, tap-changers, connections and current transformers; brittleness of gasket materials. In general, the larger the transformer the more vulnerable it is.

Both the above mentioned standards give similar maximum temperature limits that should not be exceeded in case of a long–term loading beyond the nameplate rating: current 1.3 per-unit, winding hot-spot temperature 140 °C (instead of 120 °C at normal loading), top-oil temperature 110-115 °C (instead of 105 °C at normal loading). The increased ageing rate due to a hot-spot temperature of 140 °C is 17.2 times higher than normal[1] for upgraded paper insulation and 128 times higher than normal[1] for non-upgraded paper insulation [5].

RATED VOLTAGES

Finding a substitute transformer with suitable primary and secondary rated voltages is a challenging task and difficult to perform intuitively. Additionally, a transformer design for a certain voltage determines the size of the core and has a significant impact on the overall transformer size and cost.

The system and transformer medium/high/extra high voltage ratings are well standardised and correlated in ANSI C84.1 [7] and IEC 60038 [8]. However, the generator standards do not specify standard series, nor preferable values for the rated stator voltage. The generator stator voltage rating is normally determined by agreement, and in many cases, it is simply the generator manufacturer's decision in accordance with their available design. Therefore, it is quite difficult to match the UT/UAT primary rated voltage and the generator rated voltage.

Section VII deals with transformers having rated voltages lower than expected operational voltages in detail. Accordingly, it may be possible to use transformers with rated voltages higher than

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[1] "Normal" means here a relative ageing rate of 1.0, corresponding to 98 °C for non-upgraded paper and to 110 °C for upgraded paper [5]

the operational ones providing that the rated current will not be exceeded. In such cases, the substitute transformer may be practically oversized and unsuitable because of larger core size and longer insulation distances.

Ideally, it is desirable for a generator to be able to absorb Mvar to its limit when the system voltage is at its highest expected level and to produce Mvar to its limit when the system voltage is at its lowest expected level. This is seldom possible for a fixed tap setting in the UT, thus a compromise may be made by selecting the appropriate tap rating to meet the most likely operating conditions. It is important to note that the reactive power consumed by the UT will absorb a significant part of the generator Mvar output under most conditions.

Finding a substitute transformer with suitable primary and secondary rated voltages is a challenging task. Various boundaries can be analysed using graphical representations.

IEEE C57.116 [9] recommends selecting the main parameters of the UT (rated voltages, rated MVA, impedance, and over-excitation) by portraying their effect graphically under various operating conditions. While this method is mostly dedicated to a new plant project, it may also be used in case of a substitute transformer. A typical graph (Fig. 2) shows the change in generator voltage with generator reactive load for various constant transmission system voltages. The graph allows prediction of the Mvar capability (both lead and lag) at any given system voltage while keeping the ±5% generator voltage limits as required by IEEE C50.12 [10], IEEE C50.13 [11] and IEC 60034-1 [12].

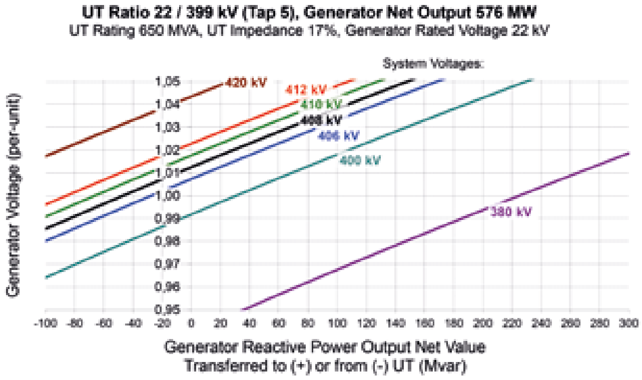


Fig. 2. Change in generator voltage with generator reactive load for various system voltages.

The example in Fig. 2 was built on a spreadsheet using equations based on transformer phasors diagram [9]. For a potential substitute transformer, such graphs should be drawn for any available tap/ratio at the anticipated MW and analysed in order to choose the most suitable tap voltages (according to the forecast of the system voltage profile) that will pose minimum restrictions to the unit operation: range of available Mvar, synchronization ability, etc. Of course, a substitute transformer may not allow a full range of loading; normally some limitations (e.g. in reactive capabilities) may be acceptable.

References [13] and [14] propose other graphs, more complete but also more complex, which take additional restrictions into consideration, such as: generator maximum excitation limit, generator under-excited reactive ampere limit, UT limits (at lower than rated tap voltage), turbine MW limit, and auxiliary bus-bars (motors) voltage limits. Such graph shows the reactive power transferred to/from the grid (at UT high voltage side) as a function of system voltage and forecasts the area of allowable operation. This graph can also be obtained in a spreadsheet using suitable equations (Fig. 3).

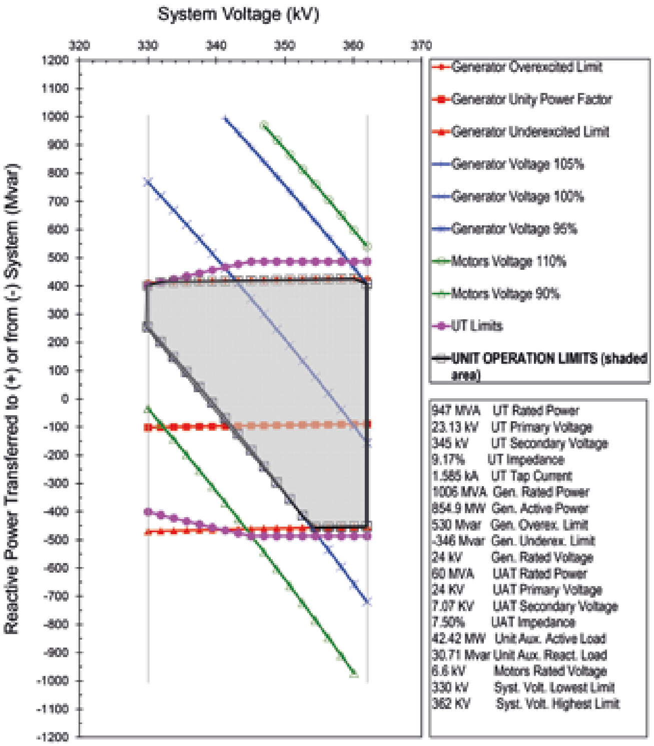


Fig.3 Reactive power transferred to/from system as a function of system voltage (operation area limit).

OVERVOLTAGE LIMITS

The purpose of this section is to show how low the substitute-transformer rated voltages can be in order to withstand the highest expected voltages on its terminals.

The standards define the maximum winding voltage based on the insulation withstand capability (in IEC 60076-3 [15] it is called the highest voltage for equipment, while in ANSI C84.1 [7] it is the maximum system voltage).

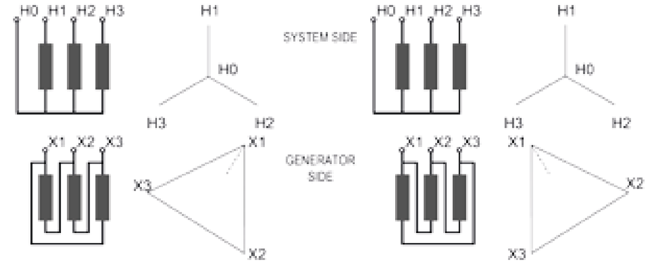
According to (1), the ratio between voltage and frequency (V/Hz) of the system to which the transformer is connected determines the nominal flux density at which the transformer operates (assuming the number of turns at a particular tap will remain constant). Normally, the transformer is economically designed to operate at as high as possible flux density while avoiding core saturation. System frequency is normally controlled within close limits, thus the system voltage is the main factor responsible for over-fluxing (over-excitation). When the V/Hz ratios are exceeded, magnetic core saturation of the transformers may occur and significant stray flux may be induced in non-laminated components that are not designed to carry flux. This can cause severe localised overheating in the transformer and eventual breakdown of the core assembly and/or winding insulation.

As mentioned above, the IEC 60076-1 [3] definitions imply that the rated voltage is applied to primary winding and the voltage across the secondary terminals differs from the rated voltage (defined in no-load condition) by the voltage drop/rise in the transformer. Accordingly, by IEEE C57.12.00 [16] the rated output is delivered at rated secondary voltage; according to IEEE definition, the allowance for voltage drop has to be made in the design so that the necessary primary voltage can be applied to the transformer (at the secondary load lagging power factor of 0.80 or higher). For instance, a UT with the 15% impedance (typical range: 13–17%) designed according to IEEE shall withstand primary voltages as high as 110% of the rated value continuously when fully loaded at the 0.80 power factor (value calculated by using the transformer equivalent circuit). Such hidden capability will not be available in the case of a transformer abiding by the IEC requirements.

According to IEC 60076-1 [3], a transformer is capable of continuous operation up to 105% voltage or V/Hz (the standard meaning is per each winding). IEC 60076-8 [17] adds that this is not meant to be systematically utilised in normal service but should be reserved for relatively rare cases of emergency service at limited periods of time. IEEE C57.12.00 [16] defines the overflux capability in a different way: the secondary voltage and V/Hz up to 105% of rated values when load power factor is 0.80 or higher (lagging). Taking into account the previous considerations, this additional requirement may result in 10-15% primary overvoltage (and over-excitation) for a fully loaded generator step-up transformer (UT) built according to IEEE. Fortunately, generators are only capable of continuous operation up to 5% above or 5% below their rated voltage, by [10]-[12] (i.e. V/Hz until 105% at generator base) so the above overvoltage capabilities are rarely exploited. For UAT and SST the impedance is usually smaller than for UT. They often work while not fully loaded and the primary voltage normally does not rise by more than a few percentage points for a secondary increase of 5%.

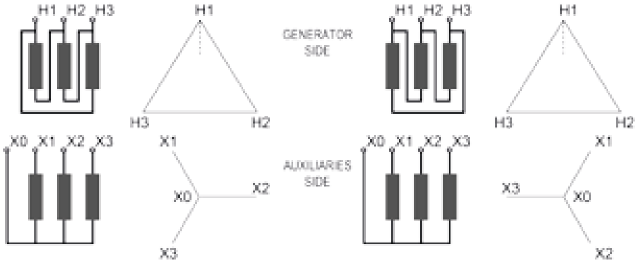
> **Overvoltage limits, as defined by various standards, have to be carefully examined and understood regarding the operation conditions to prevent any incompatibility.**

Another aspect related to the overvoltage is whether the UT and UAT will be subjected to load rejection. Sudden loss of load can subject these transformers to substantial overvoltage. If saturation occurs, substantial exciting current will flow which may overheat the core and damage the transformer. A sudden unit unloading during a fault occurrence may be caused by the clearing of a system fault, hence the machine may exceed the limit of its excitation system. The unit transformer may be excited with voltages exceeding 130% of the normal [18], [19]. With the excitation control in service, the over-excitation will generally be reduced to safe limits in a few seconds; with the excitation control out of service, the over-excitation may be substantial and damage can occur (unless dedicated V/Hz protection exists). Both IEC 60076-1 [3] and IEEE C57.12.00 [16] allow continuous operation at no load at the voltage or V/Hz up to 110% of the rated values. For a particular case of transformers connected directly to generators in such a way that they may be subjected to load rejection (i.e. configurations without generator breaker), [3] there is an additional requirement: to be able to withstand 1.4 times rated primary voltage for 5 seconds.



a) YNd1 b) YNd11

Fig. 4 Most common connection/phase displacement used for UTs.



a) Dyn11 b) Dyn1

Fig. 5 Most common connection/phase displacement used for UATs.

CONNECTION ARRANGEMENT AND PHASE DISPLACEMENT

Normally the high voltage system is grounded, leading the UT's high voltage windings to be star connected with the neutral often solidly grounded. The reason for this is mainly related to the equipment insulation level and system protection requirements. The significant consequence regarding the transformer high voltage windings is the possibility to use non-uniform, cheaper insulation systems (i.e. the neutral terminal insulation is designed with a lower insulation level than assigned to the line terminals). On the other hand, it is convenient to have the low voltage winding delta connected (the delta circuit provides a path for third-order harmonics of the magnetising currents, thus reducing the voltage waveform distortion. It also stabilises the neutral point potential in the case it is left ungrounded). The most common connection / angular (phase) displacement used for large UTs is YNd1 [9], [14], however YNd11 is also encountered (Fig. 4).

For similar reasons, the UAT primary windings (connected to the generator side) are usually delta connected while the secondary ones are star connected through a current-limiting resistor. The most common connections used for UAT are Dyn11 [14] or Dyn1 [9] (Fig. 5). According to IEEE C57.12.00 [16], in Yd or Dy transformers, the low voltage will lag the high voltage by 30°; the connection Yd1 for step-up transformer matches this standard, while Dy11 for step-down transformers does not. However, a standard Dy1 UAT with phase sequence externally reversed on both sides, as explained below, is equal to Dy11. The IEC standards do not have such restrictions.

The connection configurations, phasor group (angular displacement) and layout terminal marking (sequence) differ according to the American or the European standards.

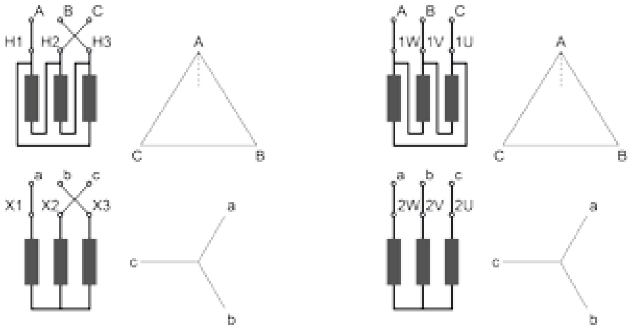
If the UT is YNd1 and the UAT is Dyn11, the medium voltage auxiliary system has zero-phase shift compared to the high/extra high voltage system (Fig. 1a). During unit start-up or shut-down, the medium voltage busses fed from the UAT and SST secondary windings are briefly paralleled (by the fast transfer scheme), so must both be in phase. Additionally, the high and extra high voltage systems are always in phase so the SST must produce zero-phase displacement and therefore, it is usually a star-star as YNyn0 transformer. In the same case it will have a delta-connected tertiary winding for the reasons mentioned above. For modern transformers, it is a matter of the grid configuration and/or protection requirements whether the SST is provided with a delta tertiary or not.

The connection configurations and phasor groups are drawn in Fig. 4. and 5. according to IEC 60076-1 conventions [3]. Since this standard mentions that terminal marking on the transformers abides by the national practice, Fig. 4. and 5. use the American practice - IEEE C57.12.70 [20].

If the original transformer is replaced by a non-identical substitute, matching the three-phase connections and phase-angle relations may be a complicated or even an impossible task. Normally it is not possible to substitute a UT or UAT having the vector group number 11 with a vector group number 1 transformer (or the opposite). The reason was explained above: these two transformers are a link between two rigid phasor systems. Only if a unit is equipped with generator breaker (Fig. 1b), it may be possible to use a YNd11 UT instead of a YNd1 one (or vice versa) assuming no rapid transfer is performed on the other auxiliary bus-bars. However, such substitution will affect the secondary circuits (at least the differential protection) and changes will be required in relay settings, and/or matching through intermediate transformers. It is recommended to also check any potential influence on synchronising circuits. It is a good practice to use supervision sync-check relay with two or three phase-sensing circuits.

Theoretically, it is possible to keep the original vector group while using a transformer from a different group. For example, an UAT from vector group 11 may be used in place of the original device from vector group 1 (or vice versa) by reversing the phase sequence on both sides of the transformer. Such change is shown in Fig. 6a, as viewed from the external line connections; the Dy11 transformer became a Dy1 one. Unfortunately, the rigid isolated phase bus bars on the generator side and non-segregated bars on medium voltage side will not allow such cross-connections in most cases.

The substitution may be complicated by the transformer layout terminal marking and sequence. According to IEEE C57.12.70 [20], the terminals are marked as in Fig. 7a, i.e. the H1 lead is presented as the right-hand terminal when seen facing the high voltage side. Other countries may use different standards. For instance, the English practice is to locate the high voltage terminals from left to right when facing that side [21]; according to the German DIN 42402 rule, the terminals are arranged from right to left as viewed from the low voltage side [22] (Fig. 7b). For instance, if an UAT designed according to the German standard with a vector group Dy11 is installed instead of the original UAT designed according to the American standard without any change to the external connections, it will externally appear as a Dy1 transformer (Fig. 6 b).



a) Dy11→Dy1
By reversing the phase sequence on both sides of the transformer

b) Dy11→Dy1
By using a substitute transformer with different terminals layout

Fig. 6. Modifications of transformer phase displacement.

a) American practice (IEEE C57.12.70)

b) German practice (DIN 42402)

Fig. 7. Transformer layout terminal marking.

Taking into account both the vector group and the terminal sequence aspects, an Yd1 American transformer is interchangeable with a European Yd11 without any external modifications.

TAPS AND TAP-CHANGER

The original transformer may be equipped with on-load tap-changer or de-energised tap-changer. Normally a substitution for a limited period of time with a fixed turns-ratio transformer will be possible in an emergency. When choosing the most suitable tap of the substitute transformer, it is indispensable to check whether it is a full-power tap (e.g. suitable for a current equal to the rated power divided by the tap voltage).

According to IEEE C57.12.00 [16], whenever a transformer is fitted with de-energised taps, they will be full capacity taps. Transformers with on-load tap-changer will be capable of delivering rated MVA at the rated voltage and from all taps above the rated voltage. However, from the taps below the rated voltage, they will be capable of just delivering the rated current related to the rated voltage (i.e. these taps may be of reduced MVA, unless specified otherwise). By IEC 60076-1 [3] all taps shall be full-power taps, except when specified otherwise.

Almost all transformers used in power plants are equipped with at least de-energised tap-changers. Sometimes, especially in case of units equipped with generator breakers, it is difficult to ensure suitable voltage of the unit auxiliaries under any operation regime. To overcome this problem, the UAT with on-load tap-changer may be required. In some cases, UT or SST are equipped with on-load taps instead of de-energised taps to allow for large variations in transmission system voltage.

IMPEDANCE

When designing a new plant, the selection of transformer short-circuit impedance (in fact the reactance, the resistance being negligible for large transformers) is subject to conflicting demands: low enough to limit the voltage drop and to meet stability requirements but also high enough to set the system short circuit levels according to the economic limitations of the switchgear and other connected plant. If a generator breaker is used, regulation of the UAT with the generator offline should also be considered. These aspects should also be considered for a replacement transformer.

Different impedance of replacement transformer can affect the switchgear capability, voltage drop, and parallel operation.

Since reactance is a result of leakage flux, low reactance is obtained by minimising leakage flux, and doing this requires a large core and an expensive transformer. Accordingly, if high reactance can be tolerated, a smaller core can be provided and a less expensive transformer.

It should be noted that since the rated MVA (S) appears in the numerator of the expression for percentage impedance (z%) calculated from its ohmic value (Zohm), the value of percentage impedance tends to increase as the transformer rating increases:

$$z\% = \text{Zohm} \times S / U2. \tag{2}$$

That means that large MVA at low impedances may require significantly bulky transformers and permissible transport limits of dimensions and weight may be reached. It is at this stage that the use of single-phase units may need to be considered.

UNBALANCE WHEN USING SINGLE PHASE UT

In addition to all the issues discussed in this paper that must be considered when selecting a substitute transformer, single-phase transformer replacement from a three-phase step-up unit introduces additional concern: neutral current unbalance of the generator.

Neutral current of the main generator is monitored in many power plants, particularly those with large generating units. Neutral current can be the result of a ground fault on the generator stator windings, on the circuit (isolated phase bus or cables) between the generator and UAT(s) and UT or on the delta-connected windings of the UT or UATs. Upon exceeding certain amplitude, the generator neutral current sets the alarm off and may also trip the unit through an overcurrent relay in the neutral circuit or through an overvoltage relay connected across the neutral resistor.

A slightly different turns ratio and/or different impedance (resulting in different regulation) between the substituted transformer and the other two will result in voltage unbalance, and negative sequence voltages and currents. This condition will not lead to an increase in the generator neutral current although it introduces other problems discussed elsewhere in this paper. However, different winding capacitances to the ground between the substituted and the other two transformers will result in an increase in neutral generator currents with possible adverse effect on the protective scheme of the generator neutral.

Fig. 8 shows a typical arrangement of a large generator grounded to the neutral via a single phase grounding transformer with a resistive load connected to the secondary winding, sized to reduce any fault current up to about 15 to 25 Amps. The sizing of the neutral resistor is a simple calculation that can be found in any good book on generator protection or in the IEEE standard C62.92.2. It is mainly dependent on the value of the capacitance of the generator to the ground as well as all other equipment connected to its stator leads. Fig. 8 shows the winding capacitances to the ground and the isolated phase bus for each of the three phases. In the figure, the capacity to the ground of the UT and UAT(s) are lumped in a single delta-connected component.

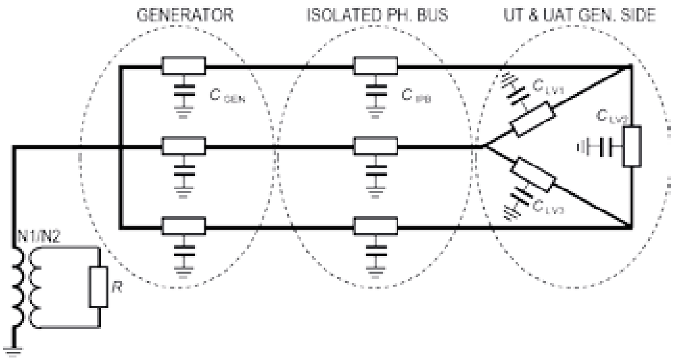


Fig. 8 Equivalent Circuit of the generator, isolated phase bus, and the delta-connected windings of the UT and UATs.

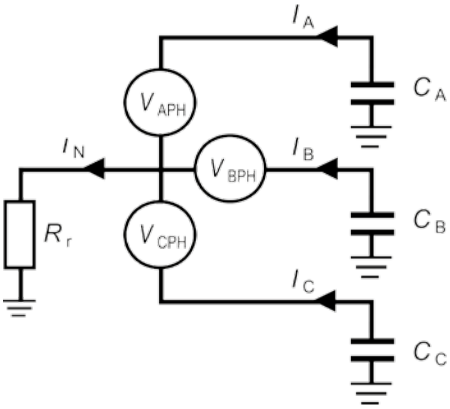


Fig. 9 Simplified circuit for calculating the unbalanced neutral current.

Under normal conditions, all the capacitances to the ground are balanced among the phases and the neutral current is very close to zero. However, if a substitute one-phase transformer is installed with different capacitance, the circuit becomes unbalanced and the neutral current grows. Finding the value of unbalanced current requires solving the unbalanced circuit through the usage of any of several available methods. One such method requires delta connection of capacitors to be replaced by its wye (star) equivalent. All series resistances and reactance are neglected.

Then, Fig. 8 can be simplified to the circuit shown in Fig. 9. In the circuit, all the variables are vector quantities, with exception of Rr which is the grounding resistance referring to the primary side. Voltages are presumably balanced and generator/isolated phase bus capacitances to the ground equal in each phase. Given that the capacitance reactance to ground is much higher than the series impedance of the windings/buses, these last are disregarded. Then, while using superposition, the total neutral current IN can be calculated by solving a circuit for each phase as shown in Fig. 10 (example for phase A) and then adding them up.

Following the calculation of the neutral unbalanced current, proper setting of the neutral protection can be prepared.

CONSIDERING OVERCURRENT

The mechanical force and the thermal short-circuit requirements described in the transformer standards are normally satisfactory for the UTs.

However, a UAT must be designed to mechanically and thermally withstand the environment in which it operates. The standard requirements for network applications may not be adequate for certain types of three-phase through-faults on the secondary of the UAT, because of the following: slower dc component decrement, longer short-circuit duration, possibility of higher primary voltage subsequent to breaker trip (load rejection) in block schemes [9].

Another outcome is the fast load transfer from the UAT to SST (or vice-versa), which may lead, under certain conditions, to high-circulating currents flowing through the two transformers exceeding their mechanical design capability [9].

Generally, examination of the aforementioned requires a consultation with the manufacturer.

SECONDARY CIRCUITS

When using a substitute transformer, the protection circuits may have to be modified because the transformer's rated power changed, and/or bushing current transformers have different turns ratio, and/or differing secondary current or burden capabilities, etc.

Substitute-transformer's bushing current transformers, with a differently rated secondary current, ratio or burden than that of the original one may lead to saturation and wrong operation of the differential protection. If the turns ratio or vector group of the alternative transformer is different from the original unit, current transformer ratio and connections should be taken into account. Some differential relays (mainly numerical) can accommodate the phase shift of the transformer or differences in these ratios internally. Other relays (mainly electromechanical) do not have this versatility and either pose difficulties or need external auxiliary current transformers.

In case of a transformer replacement it is important to verify adequacy of the transformer over-excitation protection., Protection and output limiting functions are often provided in the generator excitation equipment but it is a good practice to additionally apply separate V/Hz protection. The curves that define generator and transformer V/Hz limits should be coordinated to properly protect the both. When the transformer rated voltage is equal to the generator rated voltage, the same V/Hz relay that is protecting the generator can be set so it also protects the transformer. In some cases, however, the rated transformer voltage is lower than the rated generator voltage and common protection may not be applicable. In that case, it is desirable to provide supplementary protection for the transformer.

Protection circuits may need to be modified and protections settings are eventually adapted when using a substitute transformer.

ADDITIONAL CONSIDERATIONS

Additional aspects that should be checked when choosing a transformer substitution are:
- details of type and arrangement of terminals, for example, connections to the overhead line, isolated phase bus or cable box, or gas insulated bus bar.
- isolated phase bus ducts with accompanying strong magnetic fields that may cause high circulating currents in the transformer tanks and covers, resulting in excessive temperatures (when corrective measures are not included in the design).
- transformers operation in parallel (e.g. half-sized UTs) which needs careful matching of phase-angle, ratio and impedance in order to avoid circulating current risks [17].
- unusual voltage conditions including transient over-voltages, resonance, switching surges, etc. which may require special consideration in insulation design.
- derating due to high harmonic load current.
- unusual environmental conditions (altitude, special cooling air temperature, explosive atmosphere, etc.).
- details of auxiliary supply voltage (for fans and pumps, tap-changer, alarms, etc.).
- sound-level restrictions.
- level of losses (usually not relevant in case of an emergency transformer substitution).

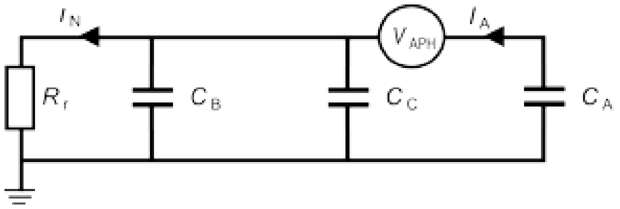


Fig. 10 One of the three circuits to be solved for calculating the neutral unbalance current.

CONCLUSIONS

Large transformers used in power plants have particular characteristics and specific custom designs. Keeping spare transformers identical to the critical ones in operation in stock is an expensive strategy, however it minimises the risk. The advantage of this policy is the increase in the multiple standardised generating units (one example of interchangeable generator transformer is detailed in [23]).

Checking the suitability of different substitute transformers is a complex task. As a first feasibility check, confirm if the transformer rated frequency fits your grid. Preliminarily look for an available transformer ratio close to the ratio of the secondary system voltage to generator rated voltage (about ±5%), and roughly estimate the transformer size, weight and available power.

Following is a partial list of the main parameters that must be checked:

- UT secondary tap voltage should not be lower than 95% of the grid's expected maximum voltage (this value typically equals the rated system voltage).
- UT primary (low) voltage should not be lower than 95% of generator rated voltage for transformers designed according to IEEE C57.12.00, and not lower than generator rated voltage for transformers designed according to IEC 60076-1.
- UAT primary voltage should normally match the rated generator voltage. A lower voltage (up to 95% of generator rating) may be possible only after investigation of the over-excitation risk.
- Check connection and phase displacement suitability.
- Analyse MVA rating suitability. If taps below the rated voltage are used, check their MVA capability.
- Transformer rated voltages higher than the expected operating ones indicate mandatory reduction of the MVA to avoid exceeding the rated current.
- Check dimensions and weight suitability.
- Analyse unbalance that may occur when swapping a single-phase transformer and an UT made out of three single-phase transformers.
- Estimate transformer short circuit impedance influences.
- Confirm through fault and fast load transfer capability in case of UAT/SST replacement.
- Verify the implications on secondary circuits (mainly protection and synchronising).
- Thoroughly analyse synchronising and loading capabilities for any available tap under various operation conditions using graphs as in Fig.2 or Fig.3.
- Check the transformer suitability for parallel operation (if pertinent to the particular layout).
- In case of two units connected to the same bus with one of them having a substitute UT (with different MVA, ratio or impedance), the possible effect on different behaviour of the generators should also be considered.

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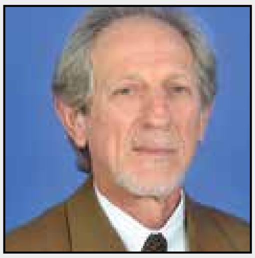

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