An evaluation of the short-circuit transient current on circuit breakers for the Hydro-Québec sub-transmission network in the presence of sub-synchronous phenomenon of the 735 kV series compensated transmission system.

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Abstract-- Since 1991, Hydro-Québec has installed series-capacitor banks on several 735-kV transmission lines to increase system reliability and improve customer service. Presently, there are 32 series-capacitor banks totaling 11 200 Mvar on Hydro-Québec`s 735-kV transmission system. Several system studies have been conducted to characterize the transient phenomena affecting the 735-kV circuit breakers during line fault clearing. These studies include: transient recovery voltages (TRV), fault currents with delayed zero crossing and sub-synchronous phenomenon. In the near future, Hydro-Québec expects to integrate new power plants far away from the load center. This integration will require additional series compensation on several 735-kV lines as well as upgrading existing series-capacitor banks. Consequently, the short-circuit currents will increase at 735-kV transmission system as well as at the lower voltage sub-transmission networks. At these substations, it will be closer to the breaking capacity of existing circuit breakers. Furthermore, due to sub-harmonic components inherent to R-L-C series circuit, the short circuit current waveforms will be quite different from the usual ones with decaying exponential dc components.

In this paper, the impact of sub-synchronous phenomenon on transient currents during a short circuit in the lower voltage sub-transmission networks at 345 kV and below were thoroughly investigated. These investigations demonstrate that, due to sub-harmonic oscillations, the classical approach consisting of characterizing the decaying exponential dc component using X/R ratios is not applicable to correctly evaluate the transient current stresses imposed on circuit breakers in many substations. To assess the breaking capability of existing circuit breakers, a new method is proposed.

Keywords: SSR phenomena short-circuit capacity, circuit breakers, series-capacitor banks.

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I. INTRODUCTION

Actually, the Hydro-Québec 735-kV transmission system includes 32 series-capacitor banks totaling 11 200 Mvar (Fig. 1.) In the near future, the integration of new power plants far away from the load center will require additional series compensation on several 735-kV lines as well as upgrading existing series-capacitor banks. Consequently, the short-circuit currents will increase on the 735-kV transmission system as well as at the lower voltage sub-transmission networks where, it will be closer to the breaking capacity of existing circuit breakers.

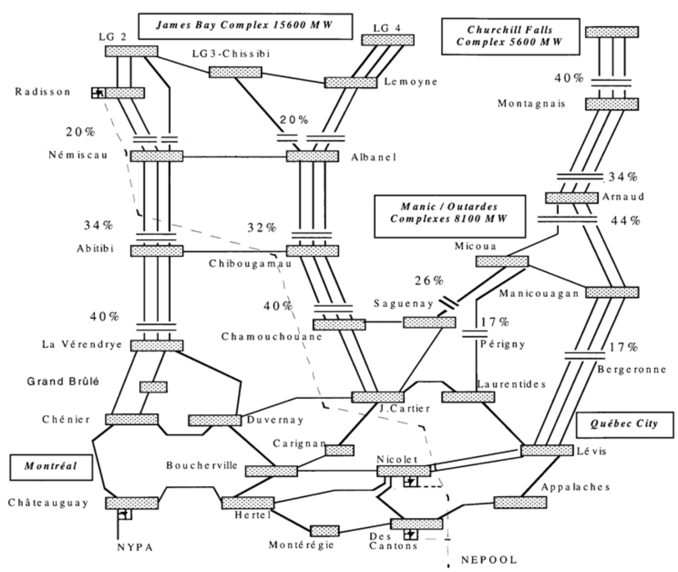

Fig. 1. Actual Hydro-Québec 735 kV transmission system.

For 735 kV circuit breakers, many studies have been conducted to characterize transient phenomena during a line fault clearing such as: transient recovery voltage (TRV), fault currents with delayed zero crossing and sub-synchronous phenomenon [1] – [2].

II. THEORETICAL BACKGROUND

It is well established [3] that, for power system where the network impedance are due mainly to lines and transformers impedances, the theoretical equation for the instantaneous fault current (i(t)) for an inductive impedance circuit is:

$$i(t)=\frac{V}{\sqrt{R^2+X^2}}*\left[\sin\left(wt+\theta-\arctan(X/R)\right)-\sin(\theta-\arctan(X/R))*e^{(-wt/(X/R))}\right] \quad (1)$$

Where:

- V stands for the voltage crest phase to ground,
- R and X the real and imaginary parts of the network impedance at fault location,
- ω the angular frequency (377 rad/s),
- t the time and θ the angle of the voltage.

We assume that, at time t=0, the voltage value (v(0)) is :

$$v(0)=V*\sin(\theta) \qquad (2)$$

Where v stands for the instantaneous voltage.

In (1), the shape of the waveform can be defined by three parameters: the symmetrical current (I_{sym}), the X/R ratio and the angle θ. The I_{sym} (an rms value) is defined by:

$$I_{sym}=\frac{V}{\sqrt{2}*\sqrt{R^2+X^2}} \qquad (3)$$

The first term in (1) is the steady-state current at frequency and the second the decay exponential dc component.

Fig. 2 shows the current waveform given by (1) for I_{sym} = 40 kA_{rms}, X/R = 30 and θ = 0:

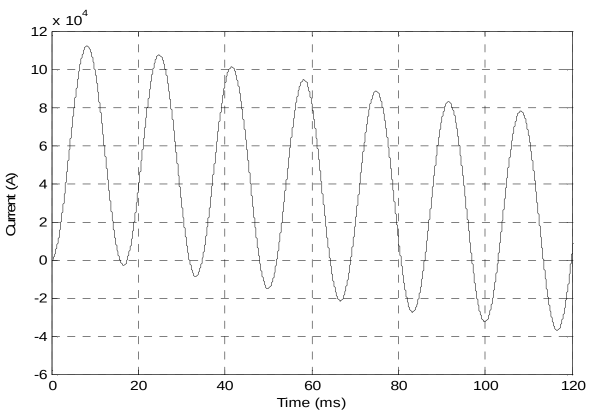

Fig. 2. Theoretical fault current waveform given by (1).

It can also be shown that the maximum value for (1) is approximately 2.7 * I_{sym} and appears after about 1/2 cycle.

If a capacitor is connected in series with a line inductance, representing 40% of its impedance, the fault current will have the waveform shown in Fig. 3. The presence of the sub-synchronous current component is obvious.

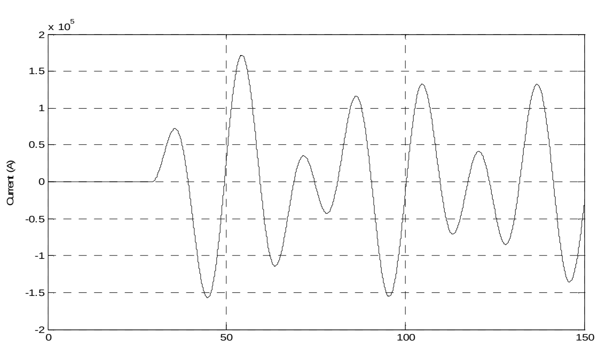

Fig. 3. Fault current for a 40% series compensated line.

III. CIRCUIT BREAKER STANDARDS

As well explained in [3], the circuit breaker standards were changed in 1964 from a Total Current Basis rating (ANSI C37.4, C37.6, etc) to a Symmetrical Current Basis rating (ANSI C37.04, C37.06, etc). The IEC 56 (1987) differs slightly from the Symmetrical Current defined by ANSI standards, but most of the requirements are the same. It is important to remember that these old standards have to be consulted for circuit breakers which have been purchased and tested in those years. In this paper, we are preoccupied by the fault current interruption capabilities of old circuit breakers.

In order to protect the system and equipment from short-circuits; these standards define clearly the method to follow in the evaluation of the capability of circuit breakers. The method presented in these standards, that from this point will be designated has classical method, compares the capability of a circuit breaker to the network fault current at the instant of separation of the main contacts of the circuit breaker. By using some approximations, which depends on the contact parting time of the circuit breaker (including the protection delay) and the X/R ratio, an asymmetrical factor is defined. Multiplying the symmetrical interruption capability of circuit breaker by this factor, a total rms value at the instant of separation of the main contact is obtained. This method is represented in the standards by a series of graphics. The asymmetrical factor can be read out from these graphics for different contact parting times in function of the X/R ratio.

These standards consider that the fault current waveform is similar to Fig. 2, i.e. a sum of two terms: a steady-state fundamental frequency term and a decaying exponential dc term. On the other hand, it is difficult to use a decaying exponential dc term in the case of the fault current waveform seen in Fig. 3.

IV. IDENTIFICATION OF POTENTIAL PROBLEMS DUE TO SUB-SYNCRHONOUOUS FAULT CURRENT PHENOMENA

On the Hydro-Québec transmission and sub-transmission systems, locations where the actual classical method is still applicable, needed to be identified. Using EMTP (Electro Magnetic Transients Program), a 3 phase fault was simulated. The fault was initiated at zero voltage (phase A). This was performed on all 735 and 345 kV buses. The duration of these faults was 150 ms (9 cycles). Also, the varistors in parallel with the series capacitor were considered in these simulations. In the evaluation of I_{sym}, only the last 16,6 ms (1 cycle of 60 Hz) of the simulation were considered for a rms calculation. To verify the applicability of the classical method at a location, an evaluation of the similarity between the theoretical waveform (1) and the simulation data was done. A non-linear least square fitting method (using MATLAB, a commercial mathematical package software) was applied to calculate the parameters of (1) using the simulated short-circuit waveform. If the classical method is applicable, the X/R ratio will be deduced from the fitting parameters. Given that the fault was initiated at zero voltage, angle θ was equal to 0 according to (2).

To quantify the evaluation of the similarity, an error parameter was defined:

$$error = 100\frac{\sqrt{\sum_{i=A}^{B} s_i^{\,2} - c_i^{\,2}}}{I_{sym}} \qquad (4)$$

Where:

- A and B represent respectively the index of the first and last simulation data point under consideration;
- s_i is the value of the simulation data;
- c_i is the value from (1) using the X/R ratio and I_{sym} fitting values;
- I_{sym} the estimated symmetrical short-circuit value.

The purpose of the division by I_{sym} in (4) was to obtain an error parameter on a relative basis. This will allow the comparison for different fault locations. A value of 0 indicates a perfect fit and a value of 100 indicates an error in the order of I_{sym}.

The simulations data was limited to values between 33.3 and 100 ms (2 and 6 cycles). The time limitations are due to the following facts:

1) the minimum contact parting time of most circuit breakers is 2 cycles;
2) a duration of 4 cycles is enough to observe the phenomena; this was based on are our experience of curve fitting.

As an example, Fig. 4 illustrates a typical fault current waveform with an error parameter of 10.7.

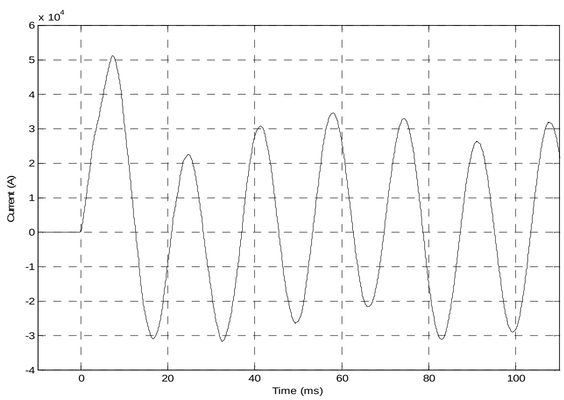

Fig. 4. Typical waveform of a three phase fault current on the 735 kV transmission system with an error parameter of 10.7.

It is interesting to note from Fig. 4 that the value of the X/R ratio obtained by the non-linear least square fitting method is small. This can be explained by the fact that when the varistors of the series compensation banks are conducting, the real part of the network impedance is higher.

It should be mentioned that the 735 kV circuit breakers have a capability of I_{sym} = 40 kA_{rms} , X/R = 30. Actually, no problems are anticipated due to the typical fault level is around 25 kA_{rms}.

In total, 102 locations were evaluated on the 735 kV system. The values of the error parameter for these 102 locations are within 49.73 and 3.26. Locations near series compensation banks are normally expected to have higher error parameter than other buses. Indeed, by visual inspection of Fig 1, 50 of theses locations are near series compensation banks. As expected, the first 30 locations in the decreasing order list of the error parameter are near series compensation. In addition, the smallest error parameter for a location near series compensation is 4.28. This value will be used for the limit of application of the classical method. For locations with an error parameter less than 4.28, the classical method can be applied. For other, a new method will be proposed in the next section.

Simulations were also done on the 345 kV sub-transmission system. 41% of locations have an error parameter higher than 4.2. For these locations, the new method will be used.

V. Evaluation of the Capability of Circuit Breakers to Interrupt Fault

It has already been said that in case of fault current waveforms like those in Fig. 3 and 4, the concept of the decaying exponential dc component (X/R ratio) is not really applicable. It is proposed to use the concept of the arc energy to evaluate the capability of a circuit breaker to interrupt fault currents.

A. Acceptability criteria for circuit breakers

Currently, the standards use the following criteria to determine whether or not a circuit breaker is able to interrupt a fault current:

1) the maximal symmetrical rms current;
2) the maximum instantaneous current;
3) the total rms current.

However, in case of the maximum instantaneous current, this value is reached during the first half cycle for a fault current waveform of Fig. 2. At that time, the main contacts of the circuit breaker are closed. For fault currents like Fig. 3 and 4, the maximum instantaneous current may appear after the main contacts begin to open. This must be considered. In the case of the total rms current, a new method has to be developed when the fault current waveforms are like the ones shown in Fig. 3 and 4.

B. Evaluation of arc energy

Some interesting discussions was found in the literature regarding the increase of the dc time constant in power systems [4]-[5] and equivalent test methods. Even though this paper do not consider the increase of the dc time constant, some considerations about arc modeling can be found in [4]-[5]. Reference [4] discuses the dependence of the arcing time on:

1) the moment of contact separation,
2) minimum arcing time,
3) instant (phase voltage angle) of fault initialization.

In [4], the arc energy for an arc voltage considered constant (E_v) is proportional to:

$$E_v \propto \int |i(t)|\, dt \qquad (5)$$

where i(t) is the instantaneous current at time t. It has been shown in [4] that the maximum current asymmetries do not always coincide with the maximum arc energy. The range of the arcing times for the last poles-to-clear is 14 to 21 ms.

Reference [5] uses an arc voltage model. This model was estimated from values measured during interruption tests. Our main objective is to evaluate interruptible capability of circuit breakers, including old ones. Unfortunately, measured values of arc voltage are not available for old circuit breakers. Therefore, it is impossible to use such an arc voltage model.

In addition to the consideration of an arc voltage constant in [4], we propose to consider also an arc resistance constant. In this case, the arc energy for an arc resistance constant (E_r) is proportional to:

$$E_r \propto \int i(t)^2\, dt \qquad (6)$$

In order to evaluate the arc energy, the first step consists of a simulation of a fault current with EMTP, neglecting the effect of the electric arc in the circuit breaker. The second step consists of the calculation of E_v and E_r by establishing respectively the lower bound, the duration of the integration and the upper bound. The lower bound is the contact parting time, i.e. the time between fault initiation and separation of main contacts (see Fig. 5.) This contact parting time is the sum of the protection delay (fixed at 0.5 cycle in the standards) and the opening time of the circuit breaker.

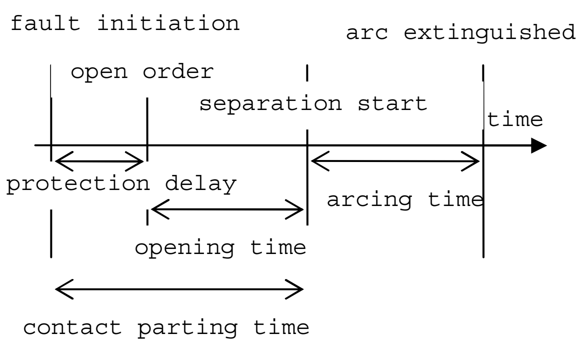

Fig. 5. Timing sequence during fault.

In case where values are unavailable, typical values for the lower limit can be used (ex: 2-, 3-, 5- and 8- cycle breakers have 1.5, 2, 3 and 4 cycles contact parting time, see [3]). The duration of the integral is equal to the arcing time. The zero-crossings, which appear between 4 and 25 ms following the integral's lower limit, define the upper bound. The usage of 4 to 25 ms is well known in T100a in IEC standards as typical values for arcing time during asymmetrical short-circuit breaking test duty.

The capability of a circuit breaker is determined by applying this method over the theoretical waveform (1) used during the tests on the circuit breaker.

C. Examples

As an example, consider a circuit breaker tested to interrupt a 31.5 kA_{rms} current with a ratio X/R of 17 and a contact parting time of 41.6 ms (2.5 cycles). Based on (1), the instantaneous calculated current is 87 kA at t=8.125 ms (see Fig. 6). In the interval between 4 to 25 ms after 41.6 ms, three zero-crossing points can be see. The maximum calculated value for E_v value is $3.3\text{x}10^7$ $A^2{\cdot}s$ and for E_r is 715 A·s.

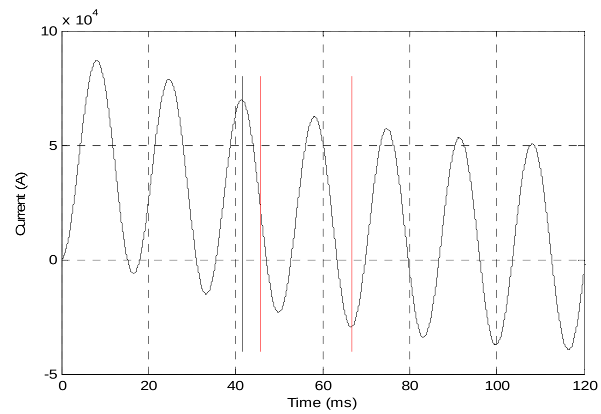

Fig. 6. Waveform of 31.5 kA_{rms} current and ratio X/R of 17. The black vertical line (most left) indicates the contact parting time of 41.6 ms (2.5 cycles) and the red lines indicate the interval 4 to 25 ms for arcing time.

It is interesting to verify the sensibility of this method to the contact parting time value. For a sweep between 33.3 and 50 ms (2 and 3 cycles) by step of 0.5 ms, the minimum, median and maximum values are extracted with their corresponding arcing time for E_v and E_r, see table 1.

TABLE I
MINIMUM, MEDIAN AND MAXIMUM VALUES FOR E_V AND E_R FOR A 31,5 KA_{RMS} X/R= 17

	E_v		E_r	
	value (10^7 $A^2{\cdot}s$)	corresponding arcing time (ms)	value (A·s)	corresponding arcing time (ms)
minimum	0.1	4.3	74	4.3
median	2.4	20.9	493	16.3
maximum	4.5	24.6	902	24.6

The differences between the minimum and the maximum values are not negligible. This will increase if the symmetrical current or the X/R ratio are higher; see table II.

TABLE II

MINIMUM, MEDIAN AND MAXIMUM VALUES FOR E_V AND E_R FOR DIFFERENT WAVEFORMS

	I symmetrical (kA$_{rms}$)	X/R ratio	E_v (10^7 A^2·s)	E_r (A·s)
minimum	31.5	17	0.1	74
median			2.4	493
maximum			4.5	902
minimum		30	0.03	32
median			3.2	589
maximum			6.0	1016
minimum	40	17	0.2	93
median			3.8	625
maximum			7.2	1146
minimum		30	0.05	42
median			5.2	748
maximum			9.7	1290

The importance of knowing the opening time of the circuit breaker (see Fig. 5) becomes obvious (Even for the method described in the standards, this opening time must be known). The protection delay will always be 0.5 cycle. Fortunately, these opening time can be easily measured during normal maintenance.

Figure 7 shows the results of two typical 3 phase fault simulations by EMTP at 315 kV buses with the waveform of Fig. 6 used as a reference to represent the circuit breaker capability.

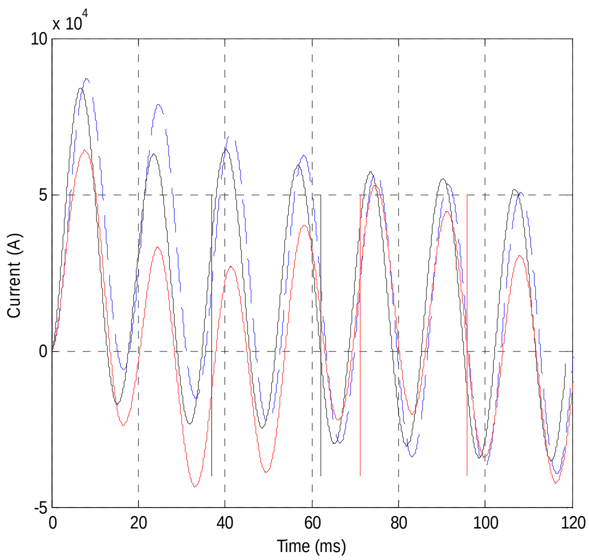

Fig. 7. Waveform of 31,5 kA$_{rms}$ current and ratio X/R of 17 (dash curve) and two typical 3 phase fault simulations by EMTP at 315 kV buses.

The non-linear least square fitting method is used to evaluate the symmetrical current, the maximum instantaneous current and the error of the waveforms. These values are respectively of 18.4 kA$_{rms}$, 84 kA and 31.7 for the black curve and 22 kA$_{rms}$, 64 kA and 7.37 for the red curve (the one reaching -40 kA). These values are lower than those describing the capability of the circuit breaker: 31.5 kA$_{rms}$ and 85 kA.

To consider the influence of the shape of the simulation waveforms on the energy calculation, the lower limit of the integration (i.e. the contact parting time) must be variable. A 0.5 ms step has been used between 33.3 and 100 ms after the short-circuit initiation. Table III presents the maximum values for the two typical 3 phase fault simulations under studies. Since the two approaches of calculating the arc energy are higher for the circuit breaker than for the simulation results, it is possible to conclude that the circuit breaker can interrupt these fault currents.

TABLE III

MAXIMUM VALUES FOR E_V AND E_R.FOR THE TWO TYPICAL 3 PHASE FAULT SIMULATION BY EMTP UNDER STUDIES AND THE CIRCUIT BREAKER CAPABILITY.

Color of curves of Fig. 7	E_v value (10^7 A^2·s)	E_v corresponding arcing time (ms)	E_r value (A·s)	E_r corresponding arcing time (ms)
black	4	24.9	863	24.9
red	2.4	24.6	674	24.6
Dash (circuit breaker)	4.5	24.6	902	24.6

In Fig. 7 the vertical lines illustrate the contact parting time (black lines at 37 and 71 ms) and the zero-crossing time (red lines at 62 and 96 ms) relative to table III. For both energy evaluation, E_v and E_r, it appears that the same contact parting time has been deduced in each simulation. It is interesting to note that for the red curve, the contact parting time is very different from the one of the circuit breaker (71 instead of 41.6 ms; see Fig. 7).

D. *Improvements of this method*

One way to improve this method is to use an arc model where the arc voltage and the arc resistance can vary. Unfortunately, these arc models are not available for old circuit breakers.

VI. CONCLUSIONS

The integration of new power plants on the Hydro-Québec`s transmission system will require new series compensation banks as well as upgrading the existing banks on the 735 kV transmission system. This will increase the level of the short-circuit currents. For lower voltage sub-transmission networks, these short-circuit current levels will be closer to the breaking capacity of the circuit breakers.

It has been illustrated that the waveform of such short-circuits can be different from those usually appearing on power system. We have developed a method to identify locations where this difference is significant.

In such cases, it is difficult to use the method described in the standards to evaluate the capability of a circuit breaker to interrupt a fault current. In this paper, we propose a new method based on proportional quantities to arc energy. The arc energy calculation, obtained by the time integration of mathematical functions of the fault current simulated waveform, is used to compare the capability of the circuit breaker with the constraint from the fault on the network.

VII. Acknowledgment

The authors gratefully acknowledge Francine Rochon and Michel Landry from Hydro-Québec for discussions.

VIII. References

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IX. Biographies

Pierre Larivière received his B. Sc and M. Sc in physics from the Université de Montréal and his B.Sc.A in electrical engineering from École Polytechnique de Montréal in 1984, 1986 and 1991 respectively. From 1991 to 1996 he has been at the field test department at Hydro-Québec where he was responsible for commissioning tests of series-capacitor bank and HVDC link. Since 1999, he is at the system studies group of the system planning department at Hydro-Québec. His main interests are in series compensation and specification of circuit breakers. Mr. Pierre Larivière is a registered professional engineer in the province of Québec.

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