Review of the IESO-Controlled Grid's Operability to 2025

Independent Electricity System Operator

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Table of Contents

INTRODUCTION **1**

Distributed Energy Resources (DERs) *2*
Changes in Load Behaviour and Modelling Enhancements *2*
Findings *3*

MOST SEVERE SINGLE CONTINGENCY (MSSC) **4**

SYSTEM INERTIA **7**

PRIMARY FREQUENCY RESPONSE **10**

TABLE OF CHARTS

CHART 1: VOLTAGE LEVELS CONTOUR DURING A SEVERE TRANSMISSION FAULT 4
CHART 2: PROJECTED IMPACT ON SYSTEM INERTIA 7
CHART 3: PROJECTED PRIMARY FREQUENCY RESPONSE FROM BASELOAD HYDROELECTRIC GENERATION FACILITIES 10

Introduction

The IESO conducts periodic operability assessments in order to evaluate its ability to effectively and reliably operate the IESO-controlled grid (ICG) into the future, and to identify and recommend changes to the ICG design or market mechanisms, processes and/or tools to address any operability concerns. The assessment considers IESO operating experiences and projects how real-time operations will be impacted by the changing technologies and resources within Ontario’s power system (both transmission- and distribution-connected).

The IESO’s 2019 Operability Assessment is a projection of the how the operation of the ICG is expected to evolve by year 2025. It also identifies any concerns the IESO must address in order to ensure the continued reliable operation of the ICG. Since the 2016 Operability Assessment, the IESO has witnessed and managed a number of changes that impact operability. The main drivers for this assessment include:

- The increased penetration of inverter-based distributed energy resources (DERs) on ICG operations
- The recognition that the IESO could support reliability by incorporating ideas, experiences and insights from other system operators
- There have been changes in how the ICG behaves during and after a transmission fault, which the IESO identified through regular monitoring of primary frequency response
- The transmission-connected supply mix has shifted from only synchronous generation facilities to more inverter-based generation facilities (e.g., wind and solar). This change has lowered system inertia, which is a critical element that supports the secure operation of the ICG, especially during light demand conditions
- The IESO identified a gap between power system study results and real-time system events

This assessment evaluated multiple scenarios, based on expected ICG changes by 2025, which include:

- The complete incorporation of the committed 900 MW of variable generation (VG)[1] and DERs by year 2025
- Retirement of Pickering Nuclear Generating Station (NGS) and the refurbishment of units at Bruce NGS and Darlington NGS
- Increased changes in load composition due to new technologies, conservation and other demand-side initiatives

[1] Variable generation (VG) facilities are connected to the transmission system.

Distributed Energy Resources (DERs)

At a high level, DERs are generation facilities or controllable load facilities connected to local distribution companies' (LDCs') systems. As one element of the gradual shift in Ontario's supply mix, the increased penetration of DERs has reduced the overall reliance on transmission-connected generation facilities to supply the loads.

While transmission-connected generation facilities (including VGs) and larger DERs are required to ride through transmission faults (i.e., remain connected and generating electricity) resulting from voltage and/or frequency variations outside of the normal operating ranges, smaller DERs behave differently. These smaller DERs installed in Ontario and elsewhere automatically disconnect as soon as the voltage and/or frequency variations are out of their normal operating ranges due to a very limited set of old ride-through requirements. This discrepancy has started to emerge as a major concern across the industry. Under certain operating conditions and following specific transmission faults, large amounts of DERs will disconnect and cease to generate electricity, which threatens to undermine grid reliability.

Currently, there are initiatives underway throughout the industry to address this situation by updating the equipment design and operating standards to include clear voltage and frequency ride-through requirements for DERs.

The IESO assessed the impact on ICG operations of increased penetrations of inverter-based DERs by 2025 by examining three system parameters that are vital for reliable operations:

- Most Severe Single Contingency (MSSC)
- System Inertia
- Primary Frequency Response

Changes in Load Behaviour and Modelling Enhancements

The IESO, like other system operators and utilities, relies on a mathematical representation, or a model, of the power system to enable power system studies for planning and operating the system. These models are used in computer simulations to operate the current system within system operating limits (SOLs), establish or modify SOLs, and identify potential deficiencies and system changes required to meet the projected future needs.

The operability assessment evaluated the recent changes in load behaviour, in particular their response to transmission faults, using the Dynamic Load Model (DLM) recommended by the North American Electric Reliability Corporation (NERC). Compared to traditional load models, this new model can simulate with a higher degree of accuracy the behaviour of emerging technologies (for example: variable frequency drives, switching power supplies, uninterruptible power supplies, LED lighting, heat recovery ventilators, etc.) that are increasingly being deployed by electricity consumers.

To function properly, the DLM needs up-to-date information about load composition, which for this study was obtained from IESO's latest conservation potential survey. As, under NERC's guidance, this model becomes widely adopted within the Eastern Interconnection, consumer participation in related surveys is likely to become increasingly important.

The modelling enhancements used to conduct this operability assessment had a twofold purpose:

- validate the model by comparing the simulated response of the ICG against actual transmission faults, and
- identify the effect of using the DLM for SOL derivation, in particular under increased DER penetration.

Continuous improvement in DER and load modelling is likely to impact future SOL derivation, which in turn will result in updated operating instructions that will enhance the IESO's ability to direct the operation of the ICG within established criteria.

Findings

By 2025, there is an emerging risk that a significant portion of Ontario's existing DER fleet may trip (and stop producing electricity) when specific, recognized transmission faults occur due to insufficient voltage and/or frequency ride-through capabilities. For planning and modelling purposes, this loss of DERs would become the IESO's MSSC due to loss of generation, exceeding typical MSSCs. Further details are provided in the next section of this report.

The ICG will have sufficient system inertia to ensure stable operation up to 2025. Further details are provided in the third section of this report.

The ICG is expected to have sufficient primary frequency response up to 2025. Further details are provided in the last section of this report.

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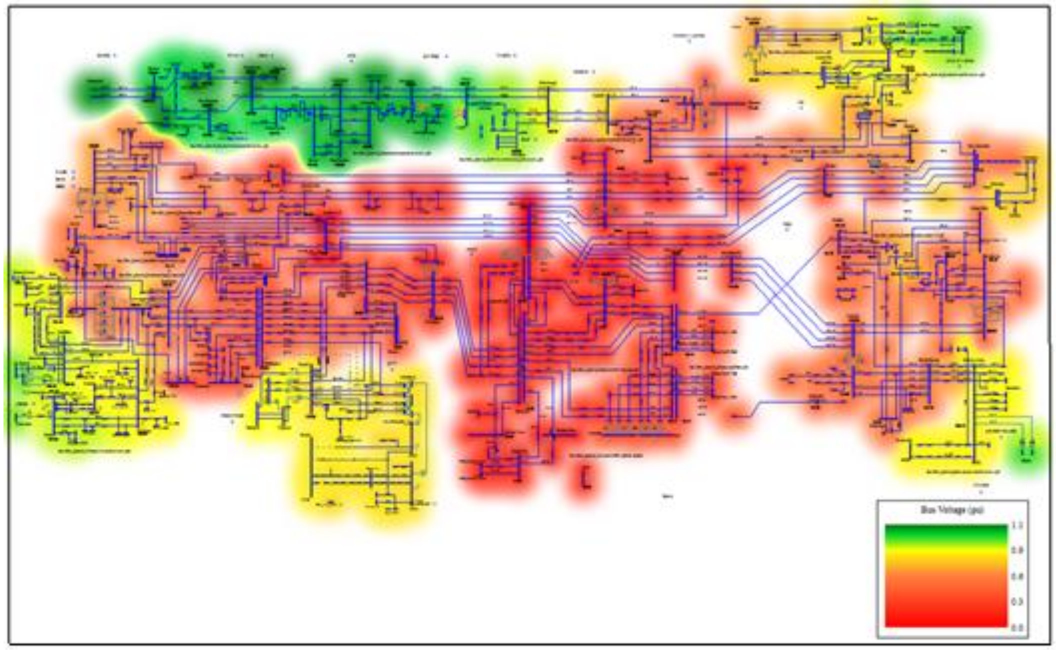
Most Severe Single Contingency (MSSC)

Chart 1: Voltage Levels Contour during a Severe Transmission Fault



What is it? The Most Severe Single Contingency (MSSC) defined in BAL-002-2 refers to generation capacity lost due to a single forced outage of generation or transmission equipment. It is one of the quantities used to determine the amount of operating reserve[2] the IESO schedules for each dispatch interval. The NERC and Northeast Power Coordinating Council (NPCC) require the IESO to schedule sufficient operating reserve to account for the ICG's MSSC.

What do we need to know? According to the NERC standard BAL-002-2, the IESO is required to develop, review and maintain annually, and implement an operating process to determine its MSSC and make preparations to have Contingency Reserve (i.e., operating reserve) equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Traditionally, the ICG's MSSC was mainly determined by the largest generation unit (one unit at Darlington NGS, approximately 900 MW) that could be lost. In some instances, some system

[2] Operating reserve is the ancillary service that consists of generation capacity or load reduction capacity that can be called upon short notice by the IESO to replace scheduled energy supply which is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies. Like any other ancillary service, operating reserve is necessary to maintain the reliability of the IESO-controlled grid.

configurations resulted in higher MSSCs – for example, if two units at Bruce NGS (approximately 1,600 MW) faulted or a group of hydroelectric generation facilities in northern Ontario (approximately 1,200 MW) became unavailable.

Projections for 2025 show the potential for 3,160 MW of DERs (total installed capacity), which could generate up to 2,600 MW during high output conditions, being in service in Ontario. The majority of DERs follow the IEEE 1547 standard for Interconnecting Distributed Resources with Electric Power Systems, issue 2003, which requires them to disconnect as soon as voltage or frequency is outside the normal ranges.

Chart 1 above shows in red those areas of the ICG where depressed voltage levels would likely cause the automatic disconnection of DERs due to a severe transmission fault within central Ontario's 500 kilovolt (kV) system. These areas are projected for 2025 to contain about 2,300 MW of DERs with a coincident high output around 1,900 MW under certain circumstances. Should a recognized transmission fault occur and these units stop producing power, this would represent the largest amount of DERs lost. Further analysis showed that a severe transmission fault within the 500 kV system that results in the loss of a Darlington NGS unit would also lead to an additional loss of about 2,000 MW of DERs with a coincident high output of around 1,700 MW, representing a total potential generation loss of about 2,600 MW.

What is it telling us? Under certain operating conditions, the insufficient voltage and frequency ride-through capabilities of the majority of DERs could result in a large-scale loss of output. That will require the IESO to plan for new and very large MSSCs.

Operability considerations? In the near term, the IESO needs to update its process for determining the MSSC in the real-time operations.

The IEEE 1547 standard was revised in April 2018 to require more advanced performance from DERs. The updated standard brings a new set of requirements for frequency and voltage ride-through capabilities such that DERs will not automatically disconnect when voltage or frequency is outside the normal ranges. This would prevent the loss of a large amount of DERs resulting from a transmission fault.

Recommendations?

1. The IESO will work with the Ontario Energy Board (OEB) to amend the Distribution System Code (DSC) to include the requirements of the new IEEE 1547-2018 standard. The IESO is in the best position to define requirements that apply to DERs in Ontario. This will ensure that all resources contribute, as needed, to maintain the reliability of the ICG.
2. The IESO will work with LDCs and the OEB to prepare a framework for performance testing of future DER connections and behind-the-meter conservation and demand management technologies, including energy storage, to ensure they have adequate voltage and frequency ride-through capabilities during and after transmission faults.

3. The IESO will work with LDCs and the OEB to formulate an implementation plan to initiate an accelerated modification of voltage and frequency ride-through capabilities in existing DERs. Updating at least 76% of the existing DERs (all DERs with installed capacity larger than or equal 0.5 MW) with new ride-through settings to provide adequate performance would allow the IESO to continue to operate to typical MSSCs. By optimizing the performance of existing DERs and reducing the need to schedule additional generation, this aligns with the IESO's strategic objective of ensuring more efficient and affordable electricity services.
4. As part of bulk system planning, the IESO will identify any cost-effective transmission reinforcements that could reduce the amount of generation lost from DERs due to a single contingency.

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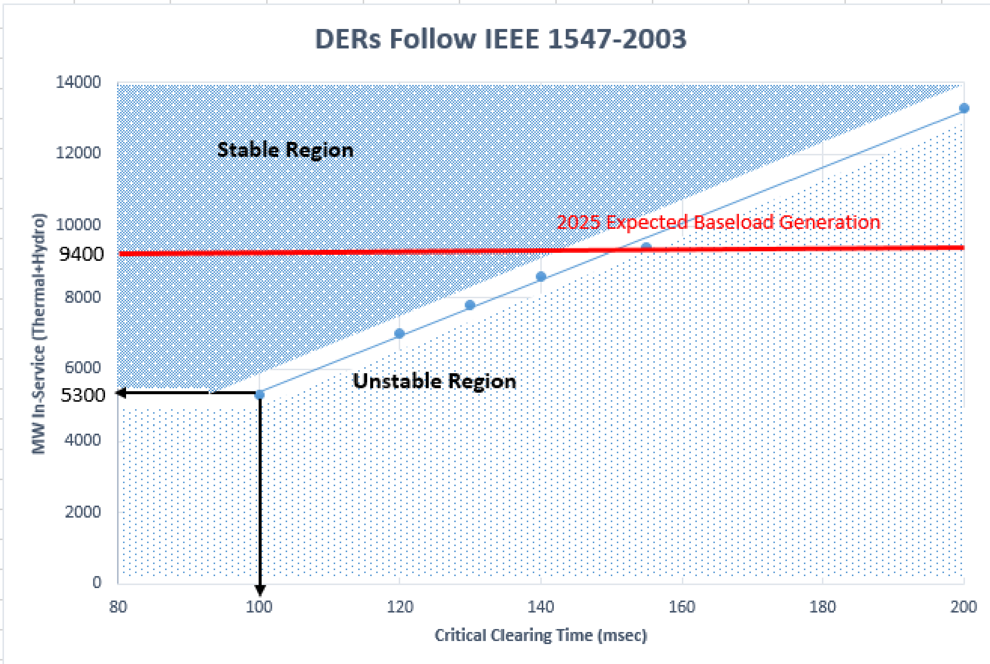
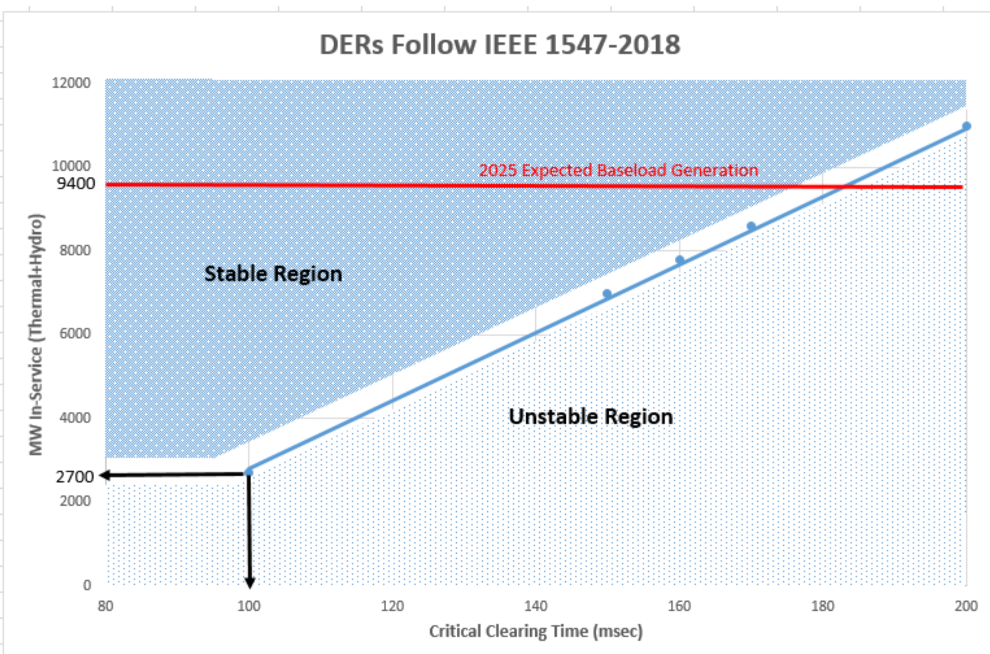
System Inertia

Chart 2: Projected Impact on System Inertia





What is it? System inertia (also known as synchronous inertia) is a property of large synchronous generation units, which contain rotating masses, to arrest frequency deviations caused by severe transmission faults, and thereby, maintains system stability. This is essential for the reliability of the broader Eastern Interconnection. Insufficient system inertia could manifest as transient instability, putting the system at risk of losing generation and/or load or causing local or widespread blackouts.

What do we need to know? Synchronous generation facilities (hydroelectric, nuclear, coal, gas-fired) are 'synchronously' connected to the grid – that is, their speed of rotation matches system frequency at all times. The rotating mass of synchronized generation facilities provides system 'inertia.' During system events when supply or load trips and causes an imbalance between the two, system inertia acts to arrest the impact of the disturbance. Inertia is independent of a unit's real-time output.

Inverter-based generation facilities (examples include wind, solar, batteries, flywheels) are 'asynchronously' connected to the grid. They have no rotating mass or the effects of the rotating mass are isolated from the grid by the inverter, and have limited abilities to provide inertia-like response.

A large-scale deployment of inverter-based generation facilities has the potential to reduce the amount of available system inertia. As this situation could have reliability impacts, NERC, NPCC and the IESO are actively exploring options to mitigate any risks.

Currently, the Eastern Interconnection has sufficient inertia, but future deployment of inverter-based generation facilities, in particular DERs, combined with low grid demand levels could potentially reduce the available system inertia to levels that are sufficiently low to pose reliability risks.

For Ontario, there are two main questions to be answered:

- What is the minimum amount of synchronous generation capacity that needs to be in service in 2025 before system instability occurs due to insufficient system inertia?
- Will existing synchronous generation facilities in 2025 provide sufficient system inertia?

What is it telling us? In the two figures in Chart 2, the critical clearing time of 100 msec shown on the x-axis represents the typical protection clearing time of a 500 kV transmission fault on the ICG. To avoid the risk of system instability due to insufficient system inertia, 5,300 MW of baseload synchronous generation facilities, composed mainly of nuclear and hydroelectric facilities, is needed when existing DERs continue to follow the IEEE 1547-2003 standard. Conversely, only 2,700 MW of baseload synchronous generation facilities is needed if existing DERs are updated to follow the IEEE 1547-2018 standard. Projections for 2025 show that Ontario's baseload synchronous generation facilities expected to be in service will be at least 9,400 MW. This would provide sufficient system inertia to ensure stable operation of the ICG.

Operability considerations? Ontario is strongly connected with the rest of the Eastern Interconnection through its interties with New York and Michigan. This also provides supplementary system inertia support to Ontario if needed. Upgrading existing DERs in Ontario with new ride-through settings (as per recommendation 3 for MSSC) will also improve system stability. The IESO should continue to assess Ontario's system inertia capability on a yearly basis to ensure adequate margin.

Recommendations? None at this time. The IESO will continue to monitor the ICG's system inertia capability.

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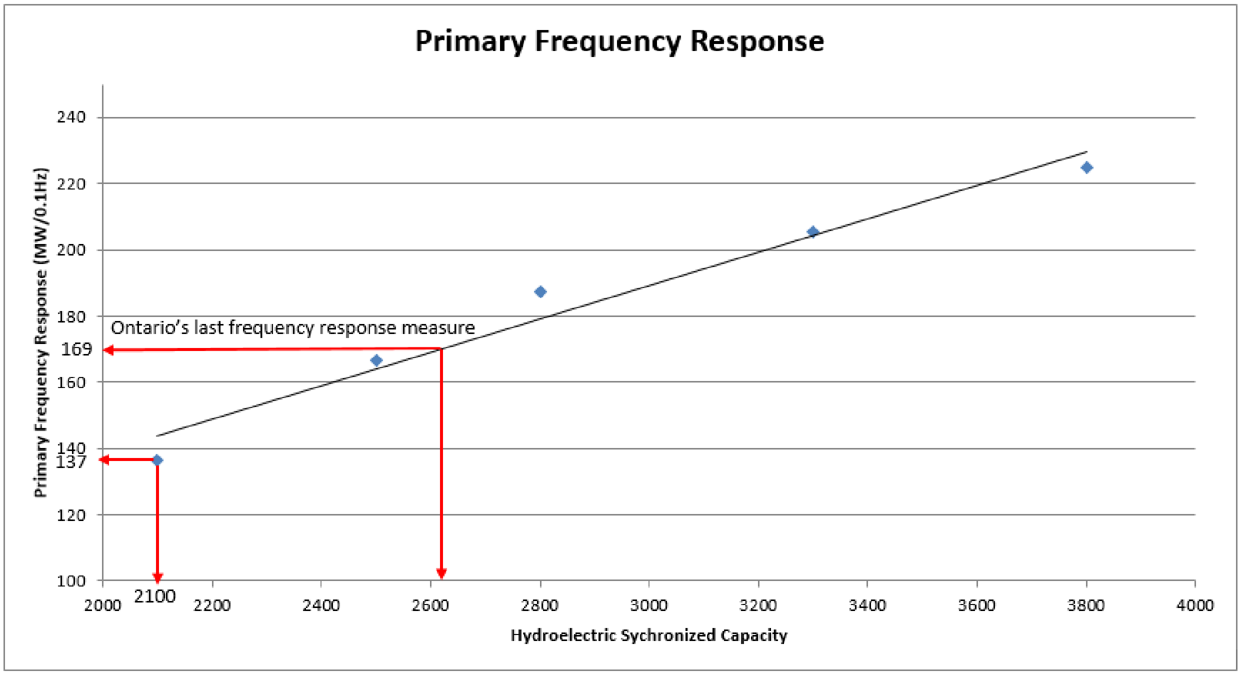
Primary Frequency Response

Chart 3: Projected Primary Frequency Response from Baseload Hydroelectric Generation Facilities



What is it? Primary frequency response describes the automatic actions of governors of synchronous generation facilities to recover and stabilize frequency in the event of a transmission fault that causes the power system frequency to deviate from the nominal level. This helps prevent the activation of under frequency load shedding (UFLS), consumer equipment damage and ultimately a blackout, and is essential for the reliability of the broader Eastern Interconnection.

What do we need to know? To ensure adequate primary frequency response in the Eastern Interconnection, the IESO must comply with NERC reliability standards BAL-001-2 (Real Power Balancing and Control Performance) and BAL-003-1 (Frequency Response and Frequency Bias Setting).

Primary frequency response, measured in MW/0.1 Hz, is mainly provided in Ontario by hydroelectric and natural-gas fired generation facilities. Most of the baseload generation facilities in Ontario, in particular nuclear, are not able to provide primary frequency response since they operate at full output power. Similarly, if a baseload hydroelectric generation unit is running at full output power, it will not be able to provide any primary frequency response. Last year, as shown in Chart 3, the IESO reported a frequency response measure (FRM) of 169

MW/0.1Hz to NERC that corresponds to about 2,600 MW of in-service hydroelectric and natural gas-fired generation facilities.

Under light demand conditions, there are very few natural-gas fired generation facilities producing power. As a result, the ICG relies primarily on baseload (run-of-the-river) hydroelectric generation facilities to provide most of the primary frequency response.

For wide-area stability across the Eastern Interconnection, the BAL-003-1 standard currently allocates a minimum contribution of 47.7 MW/0.1 Hz to Ontario.

What is it telling us? Chart 3 shows the dependency between the synchronized hydroelectric capacity and primary frequency response. In 2025, baseload hydroelectric generation is projected to provide 137 MW/0.1 Hz of primary frequency response, which is sufficient to meet the IESO's compliance obligations under NERC balancing standards. However, the IESO will continue to monitor the situation through our established NERC BAL-003-1 reporting processes. We recognize that in certain instances – e.g., when some generators are on outage and/or baseload hydroelectric generation is providing maximum output – this capability may be reduced, especially during light demand conditions.

Operability considerations? Based on the outcome and assessment of NERC BAL-003-1 reporting, the IESO may need to consider the development of a method for monitoring the primary frequency response availability in real-time operations with defined control actions to correct.

Recommendations? None at this time. The IESO will continue to monitor the ICG's primary frequency response.

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