A Quasi-Static Time-Series Approach to Assess the Impact of High Distributed Energy Resources Penetration on Transmission System Expansion Planning

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***Abstract*— Due to advancements in solar cell fabrication and inverter-based technology, as well as decreasing acquisition costs, solar distributed generation systems have emerged as a promising renewable source. Furthermore, electrification of the transportation system is an alternative promoted by many governments to mitigate the dependency on fossil fuels and achieve the goals of decarbonizing the economy. However, interconnecting a large quantity of distributed energy resources (DERs) to the power system reveals technical problems affecting the entire system. Planning coordinators and grid operators need to understand the full-spectrum impact of DERs on the power system to ensure secure and reliable grid planning and operations. The operation of a Hydro-Québec transmission system planned for 2030 is simulated in quasi-static time series mode with a massive integration of 1 million of electric vehicles and 1000 – 3000 MW of distributed photovoltaics. This paper provided findings on assessment of high DER penetrations impacts on the transmission system in terms of voltage control, mitigation means used, MVAR availability and consumption margin, generating unit optimal operation, and switching actions of several equipment.**

***Index Terms*-- Distributed energy resources, distributed photovoltaics, electric vehicles, power transmission system planning, quasi-static time-series.**

I. Introduction

Energy transition is a pathway toward the transformation of the global energy sector from fossil-based to zero-carbon by the second half of this century. Global warming is the main driving force behind worldwide interest in the generation of clean energy from variable renewable energy (VRE) [1] and the use of electric vehicles (EVs) for transportation [2]. In this context, distributed energy resources (DER) have emerged as a promising option to meet growing customer needs for electric power, with an emphasis on reliability and power quality. Their introduction into the power grid faces many challenges for transmission system operators (TSOs), distribution system operators (DSOs), and transmission planners (TPs), and highlights new market opportunities to be seized [3]. These technical challenges concern, for instance, intermittent power generation, coordination between TSOs and DSOs [4], cyber-physical security [5], stochastic system operating conditions [6] [7], and bi-directional power flow [8]. As DERs are typically interconnected in the distribution system (DS) and lower voltage networks (behind the meter), very few impact assessment studies on transmission systems (TS) have been conducted.

EVs can be difficult to study because of the uncertainty associated with their location, timeline, and potential interactions with DS and TS. High penetration of EVs implies an increase in the load due to the charging of these vehicles. The latter could impact:

1. Grid load capacity (matching supply and demand, increasing peak demand and power transit, efficiency and reliability, and aging infrastructure).
2. Power quality (voltage discrepancies, load control, harmonic distortion).

EVs penetration may raise other concerns, including economic and financial (energy losses, energy trading, cost and regulatory stress, and investment deferral) and environmental concerns regarding battery production (loss of biodiversity, air pollution, decreased freshwater supply, sustainability, and carbon footprint).

The strong penetration of photovoltaics (PVs) into DS and TS can also generate various technical challenges [9]:

1. Changes in feeders (over/under voltage, voltage unbalance, voltage fluctuation, variations in power factor, potential equipment and component overload, energy losses, and reverse power flow).
2. Power quality for system reliability and operation (frequency instability, harmonic distortion, and rotor angle stability).
3. Adaptive protection (overcurrent and overvoltage protection).
4. Reactive power support (frequent operation of voltage control and regulation devices, capacitor bank

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operation).

5. Islanding operation and islanding detection in case of grid disconnection.

With the increasing integration of EVs and PVs, TSO need multiple systems to evaluate dispatch strategies, calculate reserves, and analyze different types of stability (transient, voltage, and frequency). This article addresses this gap in the literature by implementing a quasi-static time-series (QSTS) simulation methodology for the TS. This approach refers to a sequence of steady-state power flows that are dependent on each other and allows the capture of time-dependent states of any component of the system. Discrete controls, such as capacitor switch controllers, transformer tap changers, automatic switches, and relays may change their state from one step to the next [10]. Thus, transmission planners can explore system states other than the peak or light-load demand and test many scenarios, such as adding new equipment, using alternative solutions, and deferring investments [11].

In this study, impact assessment is a set of studies that can quantify the extent of issues arising on TS and provide utilities with guidelines, solutions, and processes to manage the expected steady-state impacts of high DERs penetration. The main challenges are modeling the policies of TSOs from an operational point of view and achieving system convergence despite the main electrical constraints of system planning. The main contributions of this article are as follows.

- Demonstrating the relevance of using the QSTS approach in the TS planning.
- Assessing impact of DER on Hydro-Québec (HQ) TS for multiple future penetration scenarios of EVs and distributed photovoltaics (DPVs).
- Unlike traditional transmission planning methods, electrical variables such as mitigation means, voltage violation, deviation from optimal generating unit operation, shunt component switching actions, MVARs consumption margin, and availability are analyzed considering different system states.

The remainder of this paper is organized as follows. In Section II, the formulation and implementation of the QSTS simulation approach are presented. Section III describes the scenarios selected for the study and Section IV presents the results and discussion. The conclusions drawn from these analyses are presented in Section V.

II. Mathematical Formulation of the QSTS in Planning Transmission System and Implementation

A. *Why Use a QSTS Approach?*

Nowadays, TPs use only the peak load demand scenario, assuming it to be the worst case, to plan and ensure reliable operation of the transmission systems [12]. Non-deterministic methods (NDMs), such as probabilistic load flow and scenario techniques, consider many cases with assigning a probability of occurrence or a degree of importance to each of them. With the NDMs, either the power flow calculations are linearized, or the analyzed scenarios have no temporal dependence [13], [14].

With rapid and strong integration of VRE and DERs into the system, this paradigm is changing. As shown in Figure 1, with a QSTS simulation approach, TPs can simulate the operation of full-transmission systems from a planning perspective. This approach offers several practical advantages over traditional methods.

1. The transmission power system was represented using detailed models. Its behavior is considered with dependencies between consecutive time-step power-flow calculations.
2. The analysis was not limited to specific snapshot periods, which may no longer be the most critical. TPs can perform multiple steady-state power-flow analyses.
3. The time duration of severe conditions can be calculated.
4. It enables the study of control algorithms and interactions between control equipment and assesses the management strategies of new technologies.
5. The solutions can be optimized, and new planning methods can be tested.
6. It provides transverse vision between transmission and distribution (T&D). Impact studies on VER and DERs penetration can be of a local or systemic scope.

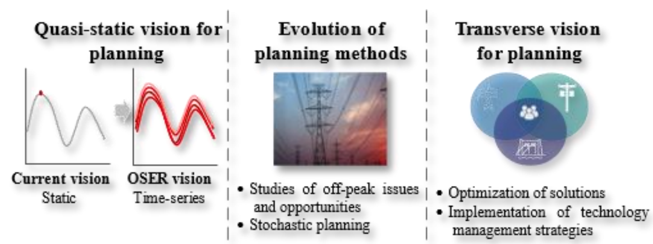

Figure 1. QSTS approach – Paradigm shift in transmission power system planning

B. *Mathematical Formulation of the QSTS Problem and the Power Transmission Systems Planning Constraints*

QSTS simulations require the availability of power profiles (demand, production, interconnection, and DERs), allowed power system topologies, and a series of configuration files: the planning system to be studied, the technical characteristics, and the locations of all equipment (loads, plants, interconnections, TSO guidance, and mitigation means ranked in order of priority). Mitigation means (MMs) are a set of resources available to avoid system security issues in supply-demand balance (SDB) and voltage control (VC). The MMs to ensure SDB include generating unit starts/stops, production redispatch, imports/exports management, demand response and lowering load region voltage. The switching actions of shunt components, the lines switching, and the static and synchronous compensators are used as MMs to control the system voltage.

The input vector $\boldsymbol{x_t}$ in (1) at time t is the combination of the vectors d_t of the system demand, p_t system production, pv_t power output of the PVs, ev_t electrical vehicle demand, ζ_t interconnection power with neighboring networks.

$$\boldsymbol{x_t} \coloneqq [d_t, p_t, pv_t, ev_t, \zeta_t] \tag{1}$$

where $d_t \in \mathbb{R}^{1\times d}$, $p_t \in \mathbb{R}^{1\times p}$, $pv_t \in \mathbb{R}^{1\times pv}$, $ev_t \in \mathbb{R}^{1\times ve}$, $\zeta_t \in \mathbb{R}^{1\times int}$ and d, p, pv, ve and int are the number of profiles for the load, production, PVs, EVs, and interconnections, respectively.

At each time step, the time-dependent state of the system is captured by solving the power flow equations and using the solution in the discrete logic of any controllable device and computation of the targeted variables. The convergent power flow solution output $\boldsymbol{y_t}$ is defined as follows in (2):

$$\boldsymbol{y_t} \coloneqq \left[V_{sc}, P_g, Q_g, T_k, V_L, Q_c, P_L, R_{res}, D_{ogo}\right] \tag{2}$$

The operational and security limits of the system, defined by the following continuous and discrete inequality constraints, must be satisfied:

- For the i^{th} $(i = 1, \dots, n_{sc})$ high-voltage bus with shunt components, the voltage magnitudes, V_{sc_i} are limited (3).

$$V_{sc_i}^{min} \leq V_{sc_i} \leq V_{sc_i}^{max} \tag{3}$$

- For the i^{th}generator $\left(i = 1, \dots, n_g\right)$, the active P_{g_i} and reactive power Q_{g_i} outputs are restricted by their lower and upper limits and are represented as (4) – (5).

$$P_{g_i}^{min} \leq P_{g_i} \leq P_{g_i}^{max} \tag{4}$$

$$Q_{g_i}^{min} \leq Q_{g_i} \leq Q_{g_i}^{max} \tag{5}$$

- Transformer taps T_k have lower and upper setting limits (6) to control n_{pq} load bus voltage magnitudes V_{L_j} (7).

$$T_k^{min} \leq T_k \leq T_k^{max} \tag{6}$$

$$V_{L_j}^{min} \leq V_{L_j} \leq V_{L_j}^{max} \qquad j = 1, \dots, n_{pq} \tag{7}$$

- The i^{th} $(i = 1, \dots, n_c)$ shunt VAR compensator Q_{c_i} has restrictions as follows,

$$Q_{c_i}^{min} \leq Q_{c_i} \leq Q_{c_i}^{max} \tag{8}$$

- As defined below, the security constraints also include the power flow limits P_{L_j} of the j^{th} $(\mathrm{j} = 1, \dots, \mathrm{n_c})$ corridor, reserve $\mathrm{R_{res}}$ over the specified threshold, and deviations from generating unit optimal operation D_{ogo} of ng groups.

$$P_{L_j} \leq P_{L_j}^{max} \tag{9}$$

$$\sum_{i=1}^{ng}\left(P_{gi}^{max} - P_{gi}\right) \geq R_{res}^{min} \tag{10}$$

$$D_{ogo}^{min} \leq \sum_{i=1}^{ng}\left(P_{gi}^{optimal} - P_{gi}\right) \leq D_{ogo}^{max} \tag{11}$$

- The load demand and the interconnection can be written as (12)-(13), where ζ_t^p and d_t^p are the profiles, ζ_t^{MM} and $d_t^{MM}$are the MMs used. For two consecutive time steps, maximum ramps can not be exceeded (14)-(15).

$$d_t = d_t^{MM} + d_t^p \tag{12}$$

$$\zeta_t = \zeta_t^{MM} + \zeta_t^p \tag{13}$$

$$\left|d_t^{MM} - d_{t-1}^{MM}\right| \leq d_{max}^{MM} \tag{14}$$

$$\left|\zeta_t^{MM} - \zeta_{t-1}^{MM}\right| \leq \zeta_{max}^{MM} \tag{15}$$

The state of the system at each time step is then defined as a vector $\boldsymbol{\Upsilon_t}$ and stored entirely in a time-series matrix for post-simulation analysis and calculations.

$$\boldsymbol{\Upsilon_t} \coloneqq \left[\boldsymbol{x_t}, \boldsymbol{y_t}\right] \tag{16}$$

C. *Implementing the QSTS Simulation Method*

The QSTS simulation approach was implemented using the OSER tool [11]. As shown in Figure 2, the independence between the operator actors in the system and the different interactions between them are modeled in several modules. The inputs in (1) are generated in the Load, Generation, and Interconnection modules. The virtual operator ensures that a convergent system is obtained at each time step and coordinates the actions to satisfy the system constraints described in (3) to (11).

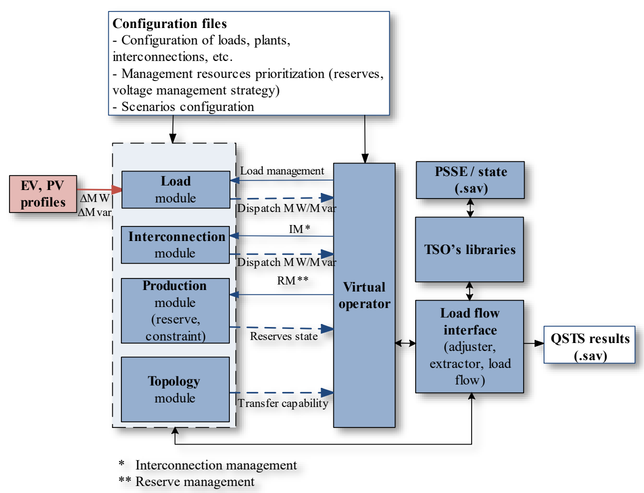

Figure 2. Overview of OSER's architecture

III. Case Studies

A. *Brief description of Hydro-Québec system*

HQ operates the most extensive transmission system in North America. It is characterized by very long distance (34000 km) high-voltage transmission lines, including >11000 km at 735 kV, which take electricity generated by large hydroelectric complexes concentrated in northern Québec to load centers in the south of "Limite Sud" [11]. Consequently, VC is a major and complex issue in the HQ system management.

B. *Scenarios description*

In its updated energy transition master plan, the Québec provincial government targeted reaching one million EVs in circulation by the end of 2030. In addition, new combustion vehicles cannot be sold starting in 2035. In Québec, peak load demand occurs during winter because of the extremely cold weather and electric heating of houses and buildings. Therefore, the penetration of EVs is studied during this period, as it is an additional load that adds stress to the system. Furthermore, approximately 700 self-producer DPVs registered in HQ's net metering program, with an average power of 700 kW. Producers not connected to the integrated electricity system (cottages, autonomous networks) were not included. The current capacity of installed DPVs is < 10 MW. Because DPVs are an additional generation and considering VC issues of HQ's transmission system, the worst case to study is adding DPVs during the summer when the system is facing light-load conditions. The addition of DPVs further reduces the net load to be fed from the system, which makes it even more sensitive to VC. The scenarios considered in these studies are listed in TABLE I. The DERs and EVs penetrations profiles considered demographic trends, socio-economic factors, and user adoption trends of new technologies.

TABLE I. SCENARIOS FOR ASSESSMENT OF THE PENETRATION OF DERS

Period	Scenario	Description
Winter peak	WP0	• Base case – Peak load demand (PLD) • Number of EVs < 170k (3% of the total vehicle fleet)
	WP1	• Integration of 1M EVs (1500 MW) • Timing of peak of charging of EVs ≠ timing of PLD
	WP2	• Integration of 1M EVs • Timing of peak of charging of EVs = timing of PLD
Summer light-load	ST0	• Base case – Light load demand (LLD) • DPV installed < 10 MW
	ST1	Integration of 1000 MW of DPVs
	ST2	Integration of 3000 MW of DPVs

IV. RESULTS AND DISCUSSIONS

The QSTS simulation approach applied to TS planning was validated with the aforementioned case studies. The impacts of large penetration of DERs on HQ's TS are assessed for three days around the winter peak and summer light-load demand. This granular analysis can be performed over longer periods.

A. *Integration of 1500 MW of EVs*

In Figure 3, the load demand profile south of the "Limite Sud" security limit point is shown for the three winter peak scenarios. Approximately 60% of the EVs are in this region. Higher loads with EVs penetration imply less reactive resource availability, whereas the higher load ramps of WP1 and WP2 increase the need to switch shunt components to maintain the voltage profiles between allowable limits. The availability of MVARs is the sum of the upper margin for all static and synchronous compensators, and the corresponding MVARs of the on-load shunt reactors and disconnected shunt capacitors. Availability includes all the equipment that can provide reactive power to the southern part of the transmission system.

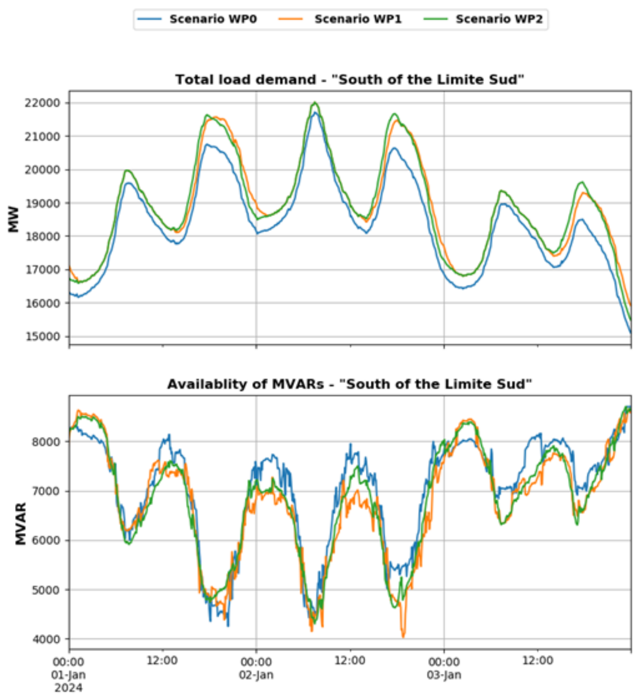

Figure 3. Total load demand and MVARs availability variations in south of the "Limite Sud" for winter scenarios

Even for WP2, there was no significant impact on the availability of MVARs to maintain voltage profiles. However, load ramps were higher in the evening at WP2. Furthermore, as shown in Figure 4, the maximum daily ramp was more accentuated during the peak day for the greater penetration of electric vehicles. The magnitudes of the average ramps were similar in all scenarios.

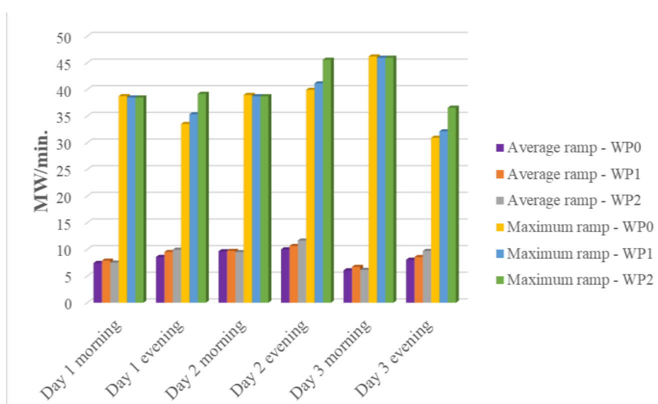

Figure 4. Maximum and average ramps for winter scenarios

Winter peaks generally occur from 6 to 9 a.m. and from 4 to 8 p.m. Figure 5 displays the mean deviation from generating unit optimal operation (D_{ogo}) per hour, as well as the total number of generating unit (GU) starts/stops. If $D_{ogo} \leq -500$ MW, all the GU are started. For WP0, this only occurred around the peak load with a deviation of up to -755 MW. However, for WP2, all the GUs started for a longer period around the peak load, and the deviation reached -1500 MW. For the WP1 scenario, D_{ogo} did not decrease as much as in WP2, but the degradation lasted longer. To maintain D_{ogo} within a specified range, the GUs were started and stopped by a virtual operator. For the EVs penetration scenarios, the number of GU switching actions was the smallest. All groups started longer, and there was no need to mitigate D_{ogo}. Moreover, the maximum number of starting actions occurred immediately before the peak load.

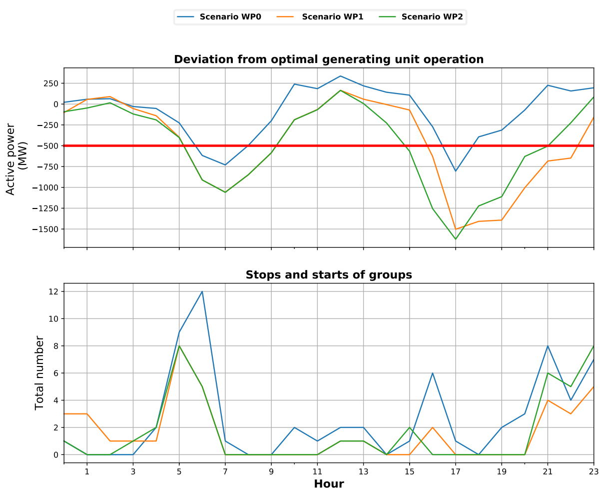

Figure 5. Deviation from optimal generating unit operation versus stops/starts of groups for winter scenarios.

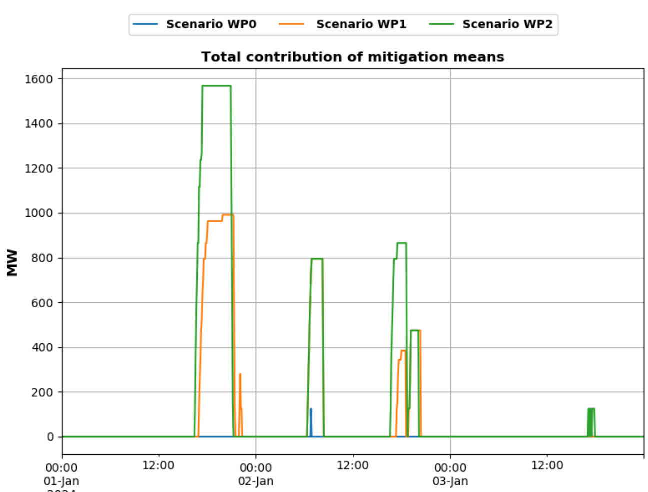

Figure 6. Analysis of the use of mitigation means for winter scenarios.

Mitigation means were required only during peak periods with increased use in the presence of EVs, as shown in Figure 6. In the base case, the maximum observed is 125 MW on the second day. By matching the peak load and EVs recharge, 1600 MW was used, whereas with EVs charging following the frequent behavior of the users, 1000 MW was reached: the first day for both scenarios.

As shown in Figure 7, the reactive powers of the static and synchronous compensators remain within the security range for all three scenarios. If a network event occurs, the compensators will have sufficient reactive power to maintain the grid in a secure and stable state in all the scenarios.

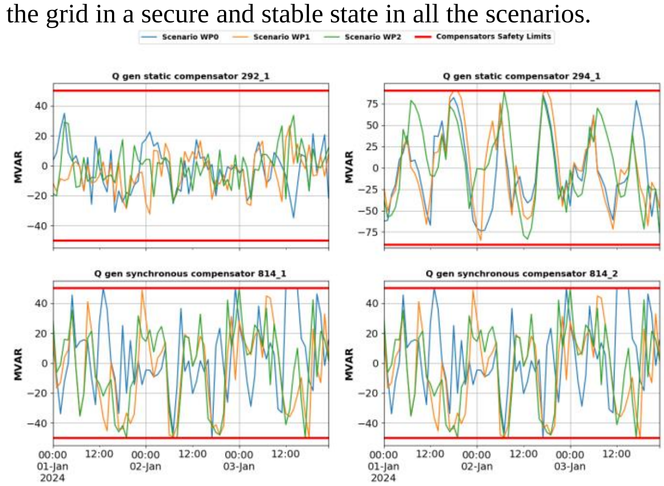

Figure 7. Qgen variation of static and synchronous compensators for winter scenarios

For all winter scenarios, as shown in Figure 8, the mean number of switching actions per hour of the shunt components was like the maximum operation when the load reached its maximum or minimum value. Subsequently, the buses at 735kV remained within the voltage safety range (725–750 and 725–760 kV). This is illustrated in Figure 9 for two buses (701 and 704). The profile setpoint range of bus 704 was very narrow. Therefore, there were more excursions outside of the set-point range.

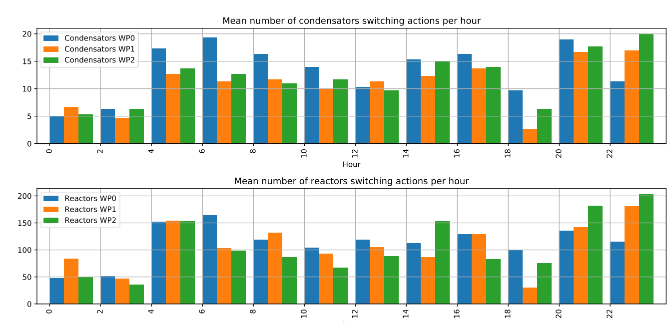

Figure 8. Mean number of switching actions per hour of shunt components for winter scenarios

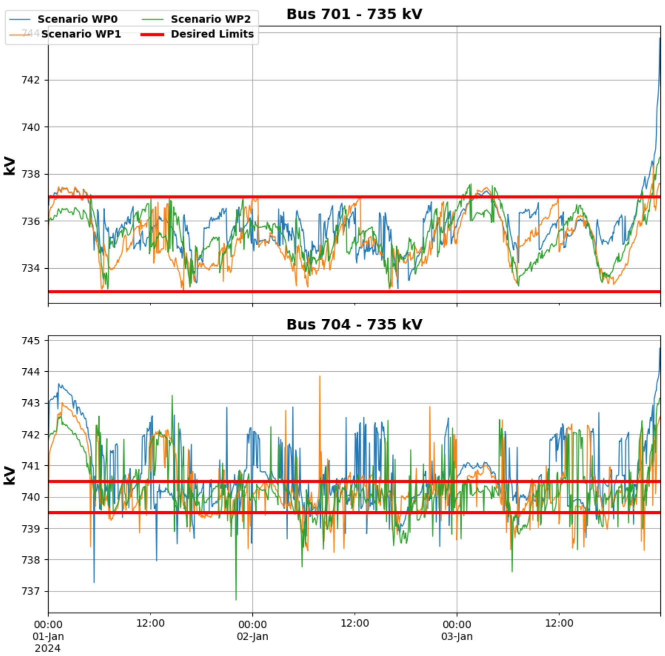

Figure 9. Analysis of voltage control at 735 kV for winter scenarios

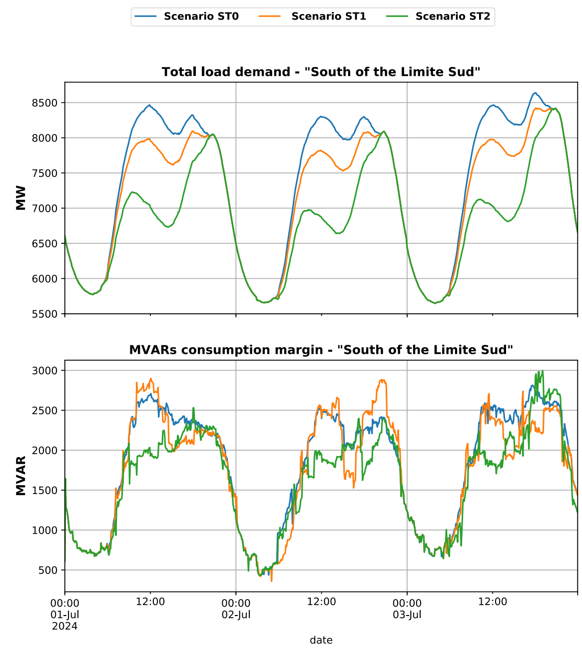

Figure 10. Total load demand and MVARs consumption margin variations in south of the “Limite Sud” for summer scenarios

Although the shunt components followed different paths in the three scenarios to ensure adequate VC at 735 kV, there were no major issues. Shunt components generally operate more in the absence of EV in the network. The challenges in terms of supply/demand balance (SDB) and their occurrence times are summarized in TABLE II. Many challenges are not captured by a static planned system, including time-dependent issues, mitigation means, and reserve management.

TABLE II. SUMMARY OF CHALLENGES CAPTURED BY QSTS SIMULATION FOR WINTER SCENARIOS

	Challenges	Occurring time
WP0	• 125 MW of MM	Ultimate peak – planned system
WP1	• 1000MW of MM	Around evening peak times
WP2	• Higher evening ramps and over 1500MW of MM	Around all peak times

B. *Penetration of 1000-3000 MW of DPVs*

For the summer scenarios, the load demand profile south of the “Limite Sud” (50% of the installed DPVs) is shown in Figure 10. For high penetration of DPVs (ST2), the MVAR consumption margin is smaller. The MVAR consumption margin is the sum of the lower margin of the static and synchronous compensators and the corresponding MVAR of all disconnected shunt reactors and on-load shunt capacitors. This margin includes all the equipment that can increase MVAR absorption in the southern part of the transmission network.

As DPVs contributed the most in the middle of the day, the largest impact on the MVARs consumption margin occurred during this time. The main trend was a reduction in the margin caused by a reduced net load. However, for intermediate scenarios, such as ST1, this phenomenon can sometimes be reversed. Variations in the shape of the margin, from none to heavy penetration, depend on many factors, such as the evolution of DPV locations. In addition, the nonlinear and discontinuous characteristics of the system control process can produce equally probable trajectories of VC with slight differences in the results.

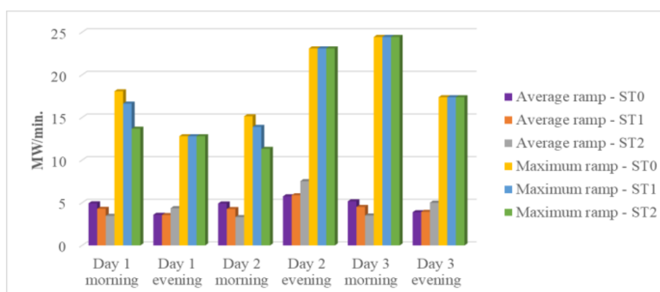

Figure 11. Maximum and average ramps for summer scenarios

As shown in Figure 11, when DPV penetration increased, the average ramp tended to decrease in the morning. However, this effect reversed in the evening. The DPV penetration does not consistently affect the maximum MW ramps.

For all summer scenarios, the mean voltages of the buses located in the southern “Limite Sud” were within the safety range, as illustrated in Figure 12. The computed reliability test signal (0 if violated, 1 if not) confirms that no voltage problems are observable at the 735 kV buses. With a lower power flow in scenario ST2, the lines were more capacitive during the day.

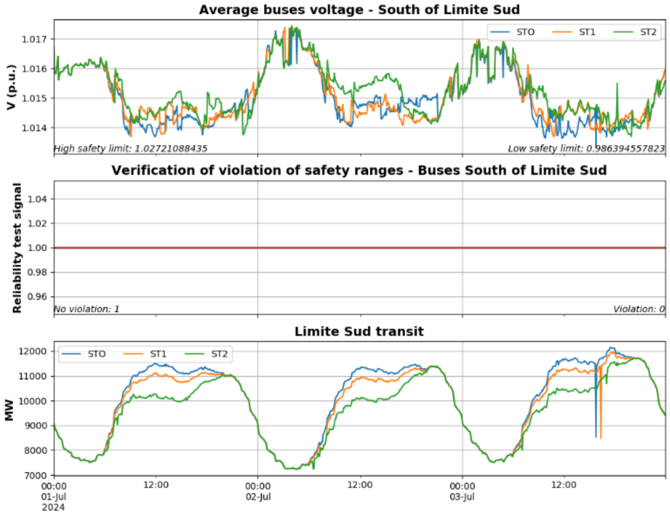

Figure 12. Analysis of voltage control at 735 kV for summer scenarios

As illustrated in Figure 13, the increasing penetration of DPVs caused a reduction in the number of stops and starts of groups in the morning. Conversely, in the evening, because of the duck curve phenomenon, an increase in the stop and start of groups was observed for scenario ST2. The addition of 1000 MW DPVs had few effects. For all scenarios, the deviation from generating-unit operation remains bounded to the desired range.

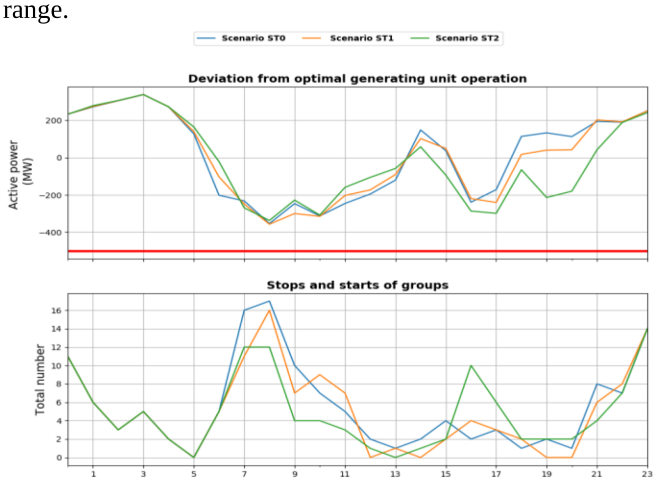

Figure 13. Deviation from optimal generating unit operation versus stops/starts of groups for summer scenarios.

When the DPVs penetration was increased, the changes in the number of shunt component switching actions shown in Figure 14 were consistent with the variations observed in Figure 10 and Figure 13. Until the afternoon, the switching actions were greater in the base case. In the evening, the penetration of PVs uses more shunt components than that in the base case. However, its effect on the transmission system is negligible.

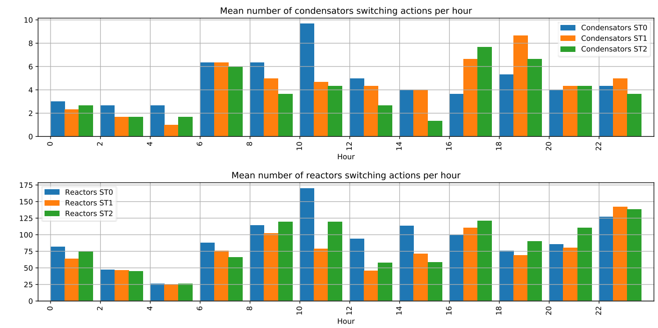

Figure 14. Mean number of switching actions per hour of shunt components for summer scenarios

In summer, the system is highly capacitive owing to low power flow. The most important remarks regarding the simulation of DPVs penetration scenarios are presented in TABLE III.

TABLE III. REMARKS ON QSTS SIMULATION FOR SUMMER SCENARIOS

	Findings
ST0	• N/A
ST1	• Low penetration scenario can momentarily lead to inverse behavior of MVARs consumption margins observed for high penetration case.
ST2	• Lower mean ramps in the morning • Higher mean ramps in the evening (duck curve)

V. CONCLUSIONS

The penetration of distributed energy resources will continue to increase significantly in the context of clean energy transition and the decarbonization of the economy. Even if these resources are in the distribution network, transmission planners must adequately evaluate their impact on the entire power system. Owing to their intermittency or mobility, these technologies can cause issues during the peak and off-peak periods. Transmission system planning using a single-reference peak system can become obsolete. Indeed, this DER penetration study performed on the detailed transmission system of Hydro-Québec provided several networks for TPs to analyze other network topologies and states outside the peak or light-load instants.

For the winter and summer scenarios, the results showed no major issues in terms of voltage control. However, the use of resources to maintain a secure and stable system differs from scenario to scenario.

For the winter base case scenario, 125 MW mitigation means were used during the ultimate peak load demand. By adding one million EVs with a charging curve reaching its maximum at the end of the evening (no coincident with the peak load), the use of mitigation means has increased sharply, bringing challenges around the evening peak hours. By making the EVs charging peak coincide with the peak load, the use of mitigation means has increased further with larger evening ramps and system control challenges during all peak periods.

For summer scenarios, the high penetration of DPVs can lead to the duck curve phenomenon. The level of penetration can create counterintuitive operational risk in the long term or lead to unoptimized system planning. Hence, an analysis tool based on QSTS simulations is important.

QSTS simulations can be used to plan and design a transmission system by testing several scenarios such as adding new equipment, using alternative solutions, and deferring investments. As seen in the discussion of the results, the worst impacts, such as the use of mitigation means, the load ramps and the voltage deviations, can occur off-peak at any time of the year. In future work, more scenarios will be studied by simulating the entire year of a planned grid in an operational context.

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