Q&A session webinar, 8 February 2022

HOW TO DE-RISK LARGE-SCALE MULTI-VENDOR HVDC SYSTEMS, LESSONS FROM THE NORTH SEA WIND POWER HUB PROJECT

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Watch the replay and download our presentation and White Paper here: https://www.rte-international.com/webinar-challenges-to-de-risk-large-scale-multi-vendor-hvdc-systems-the-north-sea-wind-power-hub-project/?lang=en

1. Do you foresee that multi-vendor interoperable hubs are viable for 2030?

Response:

We foresee that multi-vendor multi-terminal HVDC systems for offshore wind power applications may be in operation by year 2030-2033. However, such systems will have to be planned and tendered already by year 2023-2026. By the time of tendering these first systems, development projects such as the Interoperability Workstream (IWS) drafted by ENTSO-E, T&D Europe and WindEurope will not have been completed. Thus, to realize multi-vendor interoperable hubs by year 2030, it requires that TSO's or other owners are willing to take on increased risk, and invest additional efforts into de-risking of the projects. Once the first projects has been achieved, and the IWS has been completed, the way is paved for the roll-out of multi-vendor interoperable hubs for large scale roll out.

2. Where are the replicas physically installed? At the Onshore substation? Where will that be in an energy island setup with connection to potential several onshore substations?

Response:

These C&P replicas are usually installed at off-site HIL real-time lab facilities for system studies and maintenance purposes. In the case of the Johan Sverdrup project, they are installed and operated at the RTE international HIL real-time lab in Lyon. The scenario where an energy island is connected to several onshore stations poses an issue that challenges the status quo of the HIL approach. Our thoughts on possible solutions were shared in the second half of the presentation (possible directions to secure the development of large-scale offshore grids).

3. First, thanks for your presentation! I have two questions. During the operation of HVDC systems, the C&P parameters may be adjusted and changed. Could you please comment how can it be ensured that the HIL setup with C&P replicas has the identical settings as the real HVDC system during the operation? As you mentioned in the last slide in the presentation, the specifications of the EMT models need to be improved. Could you please be more specific on that?

Response:

1) The vendor would usually define a detailed procedure prior to the execution of any on-site system update, following a particular convention for update tracking. Since the C&P replicas at the HIL real-time lab facilities operate in the same software and hardware environment as the on-site installation, it suffices to follow exactly the same procedure and convention to perform the update on the C&P replicas. Our experience in working with different vendors to date shows that the system updates on the C&P replicas can be reliably executed and tracked as the on-site installation throughout the lifespan of HVDC projects with minimum human error.

2) By EMT model specifications, we were referring to a universal (to a great extent) and detailed list of requirements provided to all vendors in a multi-vendor project prior to the design phase. They can include, e.g., quantifiable performance indications of each converter control mode, expected dynamic response to setpoints, certain simulation parameters such as acceptable numerical time-steps, etc. These specifications, or rather requirements, shall be subjected to prudent verifications after model delivery.

4. Are you applying a max loss criterion for your DC system? If so, what is its basis? Are you applying AC max loss in CWE area, e.g., 3GW, or assuming max loss to each area must not exceed a limit, or do you exceed the limit transiently and across restoration? I note you have up to 6GW on the same DC busbar in your design.

Response:

The system needs to be N-1 secure, and a single fault must not lead to a disconnection larger than the N-1 dimensioning unit of each connecting area. Thus, the DC busbars must be sectioned by DC-switchgear and DC-breakers. In the case of Denmark, the maximum loss of infeed, or N-1, is currently 700 MW in the DK1 area. Thus, under these constraints, each HVDC pole in the bi-pole configuration connecting to Denmark cannot exceed 700 MW, and a "normal" fault on the DC side must not lead to the disconnection of more than 700 MW, which imposes the need for DC breakers and sectioning of busbars.

5. One of the key findings of the Odessa disturbance was the fundamental inaccuracy of offline EMT models. These are necessarily a compromise of detail needed to functionally describe performance against conventional test metrics mostly relating to classical stability phenomena. You get the model you asked for, not the one which describes the real behavior of the delivered project. A key aspect of multi-vendor and multi-terminal is making sure you understand what your model can and cannot represent and ensuring it is in-service validated. A suite of models may be needed, in particular to capture the range of non-transient behaviors present (i.e., adaptive controls, tuning aspects etc.).

Response:

We agree with your statement.

6. You are describing the convertor models, but do you have any views around the other models/ hardware needed such as supervisory controls, wide area controls, master control, DC and AC protection. One weakness of offline work is you can't interact with hardware. In our experience these additional areas of C&P are just as sensitive to inaccuracy if measurement sampling windows, filtering, data loss management, coms latency and other measurement interpretation features are not accurately captured. Do you have much confidence offline models do this? Our experience has been that they do not consistently, and some are not even available in a model.

Response:

We agree with your statement that the extended areas of the C&P system currently cannot be accurately represented in offshore tools. This issue was addressed in the second half of our presentation (possible directions to secure the development of large-scale offshore grids) as a proposition of offline PED model improvement.

7. Vendor-reconfigurable replica approaches have the potential to overcome the challenges of your large HIL, multi-lab challenge, and support sustainable expansion of your Johan Sverdrup approach, also addresses space and need for standard functionally modular approaches to drive scale and pace.

Response:

We agree that vendor-reconfigurable replicas, provided that such technology is mature and reliable, would have all the advantages you mentioned here. However, we would also like to point out that one of the main reasons why the HIL approach is being used today is that it allows the possibility to connect physical external devices. When the technology of vendor-reconfigurable replicas becomes widely accessible (which is not yet the case for most of the HVDC/OWF projects currently in operation or in planning), the HIL approach would be irrelevant as no actual physical external devices would be needed. This brings us back to the aspect of possible offline PED model improvement we addressed in the second half of our presentation.

8. Cloud approaches are great, but the issue will come joining this up with the FAT of a device. How can you define a requirement for a multi-vendor test of its hardware from only offline cloud-based studies of offline models?

Response:

We proposed the cloud-based approach as a possible improvement in offline EMT tools in order to facilitate and accelerate the iterative process established to investigate, analyze and mitigate a detected interaction phenomenon. For example, a vendor can simply insert their model into such an environment to verify the global system dynamic behavior following a system update, without going through the aforementioned (relatively time-consuming) iterative process and IP constraints. The objective is, therefore, not to replace the FAT or serve as a base for any qualitative or quantitative multi-vendor testing.

9. Are higher DC voltages more than 525kV expected to be implemented for the energy islands? Can a radial network withstand system instabilities given the connection to multiple national grids?

Response:

1. We are currently not looking into DC voltages higher than 525 kV for applications in year 2030-2033. 525 kV cables are still considered a novel technology today, but we trust that they will be the standard by year 2030.
2. This scenario of future offshore grid development would certainly be challenging and should be subjected to further studies and investigation.

10. Doesn't interoperability also mean inter exchange of data? For this reason, is it possible in the future to develop a common platform for data transfer thereby removing the IP exchange issue between different vendors?

Response:

Data exchange among different parties for the objective of model design is certainly part of interoperability issues. Instead of developing a common platform for such a purpose, we believe it would be more pertinent to enhance model interoperability with clear and specific contractual clauses between the network operator and the asset owner(s) stipulating requirements in regard to data exchange and data sharing. This approach has proven to be rather effective from our experience in several HVDC/OWF projects.

11. Why did you use a MODBUS communication (interface) protocol in the system integration layout shown in slide #45? What was exactly the role in this matter of the Norwegian company that you mentioned?

Response:

The technical considerations in terms of the communications between Kongsberg Maritime and Hitachi Energy/Siemens is beyond the responsibility of RTE international.

Serving as a master controller, the Power Management System (PMS) designed by Kongsberg Maritime carries out the following functionalities for the parallel operation of the two HVDC links:

- Control offshore load sharing between the two HVDC links based on their capacity
- Secondary offshore voltage and frequency control
- Prepare suitable conditions for the coupling and de-coupling of the two offshore HVDC converters
- Activate load shedding command under critical overload conditions

The PMS control unit is integrated in the control system of Power Distribution and Control System (PDCS), also designed by Kongsberg Maritime, which handles all automation processes and provides monitoring and stable control of the entire Johan Sverdrup electrical power network consisting of the two embedded HVDC links to shore, generators, and distribution network at 110 kV, 33 kV, 11 kV, 6.6 kV, 0.69 kV, 0.4/0.23 kV.

12. Do all the Real Time Digital Simulation platforms support the use/generation of black box DLL-based models for developing such multi-vendor interoperability studies?

Response:

Although the technical status quo of real-time simulators does not yet support the use and generation of vendor black-boxed DLL-based PED models in most of the current projects, this is certainly an interesting topic that deserves attention. We are aware that efforts are currently being made to develop a "software-in-the-loop" setup using accurate DLL-based wind generator models in real-time simulation. This would be an appealing alternative to HIL real-time simulation if the procurement of C&P replicas is not possible or not practical for various reasons.

13. As we are talking now about the fact that the manufacturers are developing new solutions for possible HVDC connections (i.e., changing basic design and C&P, etc.). So, the technology is evolving. How shall we cope with this challenge using "old" HIL/models?

Response:

Currently, either the manufacturer offline model or the C&P replica from the manufacturer delivered for a specific project is suitable for the related studies in the said project only. With the HVDC technology evolving and new solutions becoming available, it is possible to adapt these "old" offline models or C&P replicas for future projects to come, provided that in-depth expertise in control implementation (both software and hardware) is available.

14. On pages 17-19 of Laurids' presentation, several phases were shown. Who shall take the costs for connecting different HVDC connections (i.e., connections om the sea, not towards land)?

Response:

The cost distribution may be different from application to application. However, for the first phases of the Danish Energy Islands it will be the TSOs who are the owners of the transmission assets, and who have the system operator responsibility of the offshore system where the wind power is connected. Thus, in the case of the Danish Energy Islands it will be the TSO's procuring and taking the initial capital cost of the HVDC connections.

15. Is the "standardized control ENTSO-E Interface for HVDCs" (or something similar) a good starting point to be able to follow the presented approach of having a Multivendor-Ready EMT model, where the TSO would be the owner of the grid model and would connect all different detailed vendor models?

Response:

We agree with your statement. Indeed, this initiative from ENTSO-E would certainly be a good starting point to evaluate model interoperability and to develop multi-vendor ready EMT models.

Contact us for more information!

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