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Improved investment cost model and overhead cost consideration for high voltage direct current infrastructure

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***Abstract*—The ongoing large-scale deployment of offshore wind parks creates the need for substantial investments in Voltage Source Converter (VSC) based High Voltage Direct Current (HVDC) transmission infrastructure. An investment cost model with a corresponding cost parameter set was established in 2018 to improve the accuracy of HVDC grid expansion planning. As part of an ongoing initiative to continue previous work, the cost model has been updated and expanded. UnderGround Cables (UGC) are now treated similarly to SubMarine Cables (SMC) for a more accurate inclusion of onshore extensions of offshore HVDC networks. The parameter fitting methodology, which identifies the cost model parameters, has also been updated to consider different overhead costs, which increases the precision of processing cost data from real HVDC projects for parameter fitting, and, therefore, the accuracy of the cost parameter set.**

***Index Terms*—VSC, HVDC, CAPEX, Cost model, Transmission Expansion Planning**

I. Introduction

The European Green Deal and the European Commission's dedicated Offshore Renewable Energy Strategy envision more than 300 GW of offshore wind parks in Europe [1], which creates the need for substantial investments in offshore electric power transmission infrastructure. Voltage Source Converter (VSC) based High Voltage Direct Current (HVDC) technology will play a major role in this development due to its applicability for long-distance subsea cable transmission and its capability to form isolated offshore Alternating Current (AC) wind power collection grids [2]. For instance, the Dutch-German transmission system operator TenneT has a tender worth 30 G€ for such connections in the North Sea [3].

Grid expansion planning is vital in transforming energy systems, especially as potential trade-offs exist with other energy carrier networks, e.g. hydrogen networks [4]. Accurate CAPital EXpenditure (CAPEX) cost estimates of HVDC infrastructure are essential in grid expansion planning. They are necessary for determining the costs of different grid expansion options that must be compared with their benefits.

Previous work has shown that cost parameter sets for estimating the cost of HVDC transmission projects are subject to large uncertainties [5]. A cost model was defined in [5] capturing the cost of converters and cables, and the potential additional cost for converter deployment at sea. In [6], an improved cost parameter set was developed by parameter fitting that minimises cost estimation errors of real HVDC projects with a Particle Swarm Optimisation (PSO) methodology. The parameter fitting employs a logarithmic error metric and distinguishes three project categories, Back-To-Back (B2B) systems, InTerConnector (ITC) cables, and Offshore Wind Connections (OWC). To the authors' knowledge, this cost model, parameter set and fitting methodology from [6] are the state-of-the-art approach for estimating VSC HVDC infrastructure cost in energy system analysis and grid expansion studies. The contributions of this article are improvements of the cost model and parameter fitting methodology (see Figure 1).

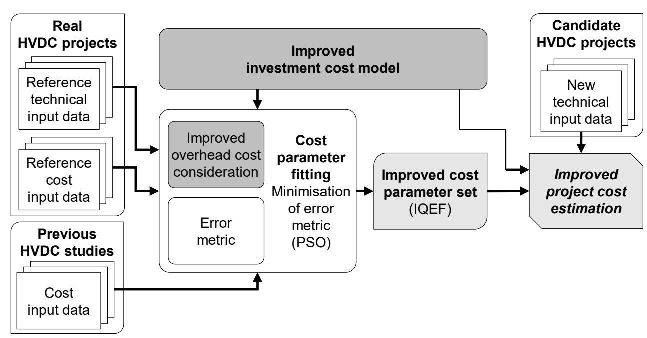

Figure 1: Schematic overview of the parameter fitting methodology for estimating VSC HVDC costs, based on [5, 6]

A few selected important abbreviations, that are necessary for understanding this article, are given below.

Term	Project category	Term	Transmission line type
B2B	Back-To-Back	SMC	SubMarine Cable
ITC	InTerConnector	UGC	UnderGround Cable
OWC	Offshore Wind Connection		

II. Improved investment cost model

A mixed-integer linear uniform cost model for estimating HVDC transmission infrastructure investment cost has been defined in [5] and this model was used for HVDC cost parameter fitting in [6]. The formulations of this cost model

(Eqs. (8) to (13)) are shown in Appendix A. Earlier versions of this cost model can be found in [7] and [8].

The mixed-integer linear approach yields significant benefits for long-term, large-scale transmission expansion planning problems and the optimisation algorithms solving them (e.g. [9], [10]), as computation time and convergence face severe challenges when more complex cost models are applied. That said, continuous linear cost models, i.e., without integer components, would be even more advantageous from a computational tractability perspective. However, such simple models fail to reflect that HVDC systems, in reality, are almost always built with high power ratings because the *per MW cost* is much higher for low-power projects. The mixed-integer linear approach, therefore, presents a viable trade-off between accuracy and the computational burden.

The linear unicorn cost model has now been updated and improved, and the new formulations are given in Eqs. (1) to (7). A full nomenclature list can be found in [6]. For readability, the most relevant terms are listed below.

Term	Explanation
$q^k \in Q^k$	Set of cost parameters
$k \in K$	Set of sources of cost parameter sets
$\mathcal{B}^k_{(\cdot)}$	Branch cost parameters of set Q^k
$\mathcal{N}^k_{(\cdot)}$	Node cost parameters of set Q^k
$\mathcal{S}^k_{(\cdot)}$	Sea cost parameters of set Q^k (node deployment at sea)
C_i	CAPEX cost of project i
$i \in I$	Set of HVDC infrastructure projects
$f \in F_i$	Set of branches for project i
$g \in G_i$	Set of nodes for project i
$g \in \tilde{G}_i$	Set of nodes located at sea for project i ($\tilde{G}_i \subset G_i$)
ω_f / ω_g	Number of parallel cable pairs of f / converters of g
γ_g	Converter rating factor of node g
p_f / p_g	Power rating of branch f or node g
λ_f	Number of segments of branch f
l_f	Length of branch f
ψ_i	Cost target year for project i

The new cost model is parameterised with nine cost parameters, which are referred to as the *cost parameter set*. It is defined for all sources $\forall k \in K$ in Eq. (1).

$$Q^k = \Big\{ \mathcal{B}^k_0, \mathcal{B}^k_{\text{lp,SMC}}, \mathcal{B}^k_{\text{l,SMC}}, \mathcal{B}^k_{\text{lp,UGC}}, \mathcal{B}^k_{\text{l,UGC}}, \mathcal{N}^k_0, \mathcal{N}^k_{\text{p}}, \mathcal{S}^k_0, \mathcal{S}^k_{\text{p}} \Big\} \tag{1}$$

The constants (also parameterising the equations) that are not part of the cost parameter set are given in Table I. In Eq. (2), the cost of a HVDC infrastructure project is the sum of the cost for all nodes, branches, and the additional cost of having nodes deployed at sea, which is defined for all projects $\forall i \in I$ and all sources $\forall k \in K$.

$$C^{k,\psi_0}_{\text{est},i} = \sum_{f \in F_i} B^k_f + \sum_{g \in G_i} N^k_g + \sum_{g \in \tilde{G}_i} S^k_g \tag{2}$$

The branch cost B^k_f are defined for all branches $\forall f \in F_i$ of a project $i \in I$ in Eq. (3).

$$\begin{aligned} B^k_f = \mathcal{B}^k_0 \cdot \lambda_f & \\ + \left(\mathcal{B}^k_{\text{lp,SMC}} \cdot p_f + \mathcal{B}^k_{\text{l,SMC}} \cdot \omega_f\right) l_{f,\text{SMC}} & \\ + \left(\mathcal{B}^k_{\text{lp,UGC}} \cdot p_f + \mathcal{B}^k_{\text{l,UGC}} \cdot \omega_f\right) l_{f,\text{UGC}} & \end{aligned} \tag{3}$$

The node cost N^k_g are defined for all nodes $\forall g \in G_i$ of a project $i \in I$ in Eq. (4).

$$N^k_g = \mathcal{N}^k_0 \cdot \omega_g + \mathcal{N}^k_{\text{p}} \cdot \gamma_g \cdot p_g \tag{4}$$

The sea cost S^k_g are defined for all nodes that are deployed at sea $\forall g \in \tilde{G}_i$ of a project $i \in I$ in Eq. (5).

$$S^k_g = \mathcal{S}^k_0 \cdot \omega_g + \mathcal{S}^k_{\text{p}} \cdot \gamma_g \cdot p_g \tag{5}$$

Based on the CAPEX cost estimation of a HVDC infrastructure project $i \in I$ for the reference year $\psi_0 = 2023$, the cost can be calculated for any given target year with Eq. (6).

$$C^{k,\psi_i}_{\text{est},i} = C^{k,\psi_0}_{\text{est},i} \cdot (1-\alpha)^{(\psi_i - \psi_0)} \tag{6}$$

The number of parallel converters for all nodes $\forall g \in G_i$ and number of parallel cable pairs for all branches $\forall f \in F_i$ of a project $i \in I$ are subject to the inequalities in Eq. (7).

$$\omega_f \geq \left\lceil \frac{p_f}{\hat{P}} \right\rceil , \qquad \omega_g \geq \left\lceil \frac{p_g}{\hat{P}} \right\rceil \tag{7}$$

The ceiling operators enforce the necessary integer investment decisions which have to be made as part of the transmission expansion planning problems.

Table I: Cost model equation constants

Constant	Old	New	Unit	Explanation
α	—	1	%/a	Annual cost reduction factor due to technology improvement
ψ_0	—	2023	a	Cost reference year
$\hat{P}$	2.0	2.2	GW	Maximum power rating for a single HVDC system

While the general concept remains the same, the cost model receives a substantial update. The following subsections explain and justify the improvements and changes.

A. Explicit inclusion of UGC

The new cost model now considers SMC and UGC as two separate transmission line type options. The old cost model considers SMC as the *main* or *reference* transmission line type and its cost conversion ratio only implicitly includes UGC, see Eqs. (8), (10) and (13) in Appendix A.

The change results in a split of the two old branch cost parameters $\mathcal{B}^k_{\text{lp}}$ and $\mathcal{B}^k_{\text{l}}$ into the four new branch cost parameters $\mathcal{B}^k_{\text{lp,SMC}}$, $\mathcal{B}^k_{\text{l,SMC}}$, $\mathcal{B}^k_{\text{lp,UGC}}$ and $\mathcal{B}^k_{\text{l,UGC}}$. Moreover, the parameter λ has been introduced, specifying the number of segments of a branch to consider the additional cost incurred by multiple segments. Typically, λ equals three for a standard ITC project, with a main SMC segment in the middle and two short UGC segments at both shores.

B. Exclusion of overhead lines

OverHead Lines (OHL) are not included in the new cost model, as only a few HVDC overhead lines are being built or planned in Europe. Similar to UGC, the old cost model only implicitly considers them by Eq. (13) in Appendix A. While OHL technically would be a third transmission line type option, they prove problematic from a public acceptance point of view. Including them in the cost model would result in transmission expansion planning outcomes that might be difficult to realise in practice. Moreover, if included in the cost model, their parameterisation would be problematic due to insufficient HVDC overhead line cost input data.

C. Inclusion of technology progress and inflation

The fact that HVDC technology is under development and subject to constant incremental improvements has been included in the cost model by Eq. (6). With $\psi_0 = 2023$ set as the reference year, the equation realises an annual cost decrease of $\alpha = 1\,\%/\mathrm{a}$.

When estimating the cost of future infrastructure investments, the cost model does not forecast the inflation rate. All cost estimations are made subject to the price level of the reference year $\psi_0 = 2023$. However, when fitting the cost parameter set based on real HVDC projects with cost data from press releases, these cost data are inflation corrected to match the price level of the reference year. Due to inflation usually being higher than $\alpha = 1\,\%/\mathrm{a}$, the absolute cost will increase over time despite the included annual cost decrease.

D. Generalisation of the B2B HVDC system representation

In the old formulation of the node cost in Eq. (11) and the sea cost in Eq. (12), the installed power rating (p_g, p_h) corresponds to the total power rating of all converters at a node. For a B2B system with two fully-rated converters in a back-to-back arrangement, this is with twice the system rating.

In the new formulation, the node cost in Eq. (4) and the sea cost in Eq. (5) have been reformulated by introducing an additional parameter γ, the converter rating factor. It generalises the inclusion of B2B HVDC systems from being fixed at exactly two connected AC systems (that are connected with the same full power rating) to an open and flexible parameter that can represent the connection of any number of AC systems, with possibly individual power ratings for the individual connections. In case of a regular HVDC transmission system, γ equals one. In case of a standard B2B HVDC system, γ equals two. The generalisation is inspired by the Tres Amigas back-to-back-to-back HVDC converter station concept [11], which, although never built, exposes the stiffness of the old approach which enforces the connection of exactly two AC systems.

The old formulation led to $\hat{P}^{\mathrm{old}}_{\mathrm{B2B}}$ being twice the size of $\hat{P}^{\mathrm{old}}_{\mathrm{ITC}}$ and $\hat{P}^{\mathrm{old}}_{\mathrm{OWC}}$ in Appendix A. With the generalisation, it is no longer necessary to define dedicated power limits $\hat{P}^{\mathrm{old}}_{j}$ for the different project categories $j \in J$, as in Appendix A. Table I only defines a single power limit parameter $\hat{P}$ without an index, valid for all project categories.

E. Generalisation of the representation of parallel systems

A new parameter ω has been introduced that represents the number of parallel cable pairs in a branch (ω_f) and the number of parallel converter stations in a node (ω_g). In the old cost model, the consideration of parallel HVDC systems was included to some extent by the ceiling operators in Eqs. (10) to (12), as shown in Appendix A. However, the old formulation did not allow for more parallel systems than enforced by the specified maximum power rating $\hat{P}$. Other than the maximum power rating, various other constraints can motivate the use of parallel systems (e.g. dimensioning fault considerations), which is also observed in real HVDC projects (e.g. SydVästlänken [12]). Thus, the introduction of ω enables the model to better match with reality.

F. Increase of the maximum power rating

The maximum power rating for single HVDC systems in the old cost model [6] was set at $\hat{P}^{\mathrm{old}} = 2.0\,\mathrm{GW}$, based on [13]. However, recent HVDC developments have shown a slight increase of the power rating $P = 1320\,\mathrm{MW}$ that in combination with the unchanged voltage rating $V = 320\,\mathrm{kV}$ results in a slightly increased current rating $\rightarrow I \approx 2.1\,\mathrm{kA}$ [14]. In combination with the highest voltage level in use $V = 525\,\mathrm{kV}$, the increased current rating results in an increased maximum power rating of $\hat{P} = 2.2\,\mathrm{GW}$.

III. Systematic Consideration of Overhead Costs

The methodology for interpreting cost data from real HVDC transmission projects is improved by adequately accounting for overhead costs. The *overhead cost* is defined as the relative overhead cost as a percentage of the corresponding *investment cost level*, on top of which the overhead cost is added. Five investment cost levels (Table II) and four *overhead cost categories* (Table III) that connect the investment cost levels are defined. The relationships between them are shown for long-distance transmission ITC and OWC projects in Figure 2.

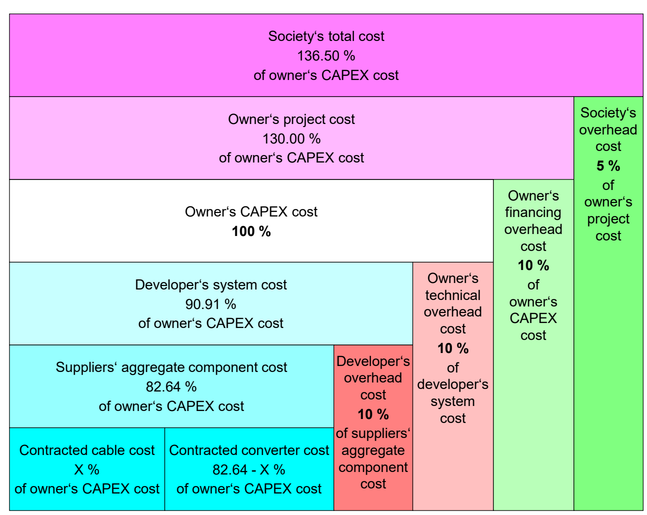

Figure 2: Investment cost levels and overhead cost categories for ITC and OWC long-distance transmission HVDC projects (bold values are exogenous assumptions), own illustration

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Table II: Investment cost levels

Investment cost level	**B2B**	**ITC OWC**	**Explanation**
Suppliers' aggregate component cost	——	82.64 %	Contracted cost of the main system components: converter and cable, incl. installation
Developer's system cost	95.24 %	90.91 %	Cost of a commissioned complete HVDC system
Owner's CAPEX cost	**100.0 %**	**100.0 %**	Complete investment cost that the owner needs to finance
Owner's project cost	130.00 %	130.00 %	Complete project cost including financing cost
Society's total cost	136.50 %	136.50 %	Non-measurable total cost including all external cost

Table III: Overhead cost categories

Overhead cost category	**B2B**	**ITC OWC**	**Explanation**
Developer's overhead cost	——	**10 %**	Engineering, electrode, PCC modifications, auxiliaries, ...
Owner's technical overhead cost	**5 %**	**10 %**	Project management, land acquisition, permission, ...
Owner's financing overhead cost	**30 %**	**30 %**	Cost of capital, insurance, risk premiums, ...
Society's overhead cost	**5 %**	**5 %**	Governmental involvement, external cost, ...

For B2B HVDC projects, the relationships are simpler due to the absence of cables, as is shown in Figure 3.

The quantification of the overhead cost values is based on [15], [16], [17], unquotable personal communication with relevant industry stakeholders, and on observations of cost data from reference HVDC projects.

Note that the term *developer* mostly refers to ABB's role when it delivered entire HVDC systems, i.e. ABB was the *supplier* of both cable and converter, and, additionally, also the HVDC system *developer*. Today, it is more common that the *developer* and *owner* belong to the same company, e.g. a transmission system operator.

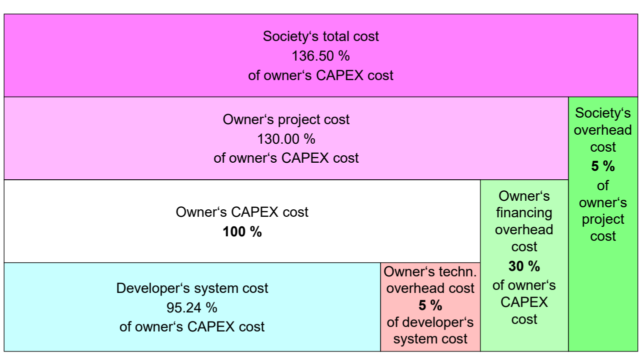

Figure 3: Overhead costs for B2B HVDC projects (bold values indicate exogenous assumptions), own illustration

A. Overhead cost calculation example

The following overhead cost calculation example illustrates the overhead cost categories and the investment cost levels for a hypothetical long-distance transmission project.

Cost of a long-distance transmission HVDC system

- ○ Contracted cable cost = 300 M€
- ○ Contracted converter cost = 200 M€
- **Suppliers' aggregate component cost**
  = contracted cable cost + contracted converter cost
  = 300 M€ + 200 M€ = 500 M€
  - ○ Developer's overhead cost = 500 M€ · 10 % = 50 M€
- **Developer's system cost**
  = suppliers' aggregate component cost + developer's overhead cost
  = 500 M€ + 50 M€ = 550 M€
  - ○ Owner's technical overhead cost = 550 M€ · 10 % = 55 M€
- **Owner's CAPEX cost**
  = developer's system cost + owner's technical overhead cost
  = 550 M€ + 55 M€ = 605 M€
  - ○ Owner's financing overhead cost 605 M€ · 30 % = 181.5 M€
- **Owner's project cost**
  = owner's CAPEX cost + owner's financing overhead cost
  = 605 M€ + 181.5 M€ = 786.5 M€
  - ○ Society's overhead cost = 786.5 M€ · 5 % = 39.325 M€
- **Society's total cost**
  = owner's project cost + society overhead cost
  = 786.5 M€ + 39.325 M€ = 825.825 M€

B. Exclusion of reported OWC cost overruns

In the previously fitted cost parameter set [6], reported cost overruns were included for the reference cost figures for some HVDC projects. Those were reported for several early OWC projects, which were more expensive than anticipated when the contract was signed. While including the upward adjustments helps to alleviate the impact of too low contracted costs, the methodology lacks the data to properly incorporate downward adjustments. These become relevant for contracted costs that are too high due to extraordinary profits and the strategic behaviour of suppliers. Since including only one-sided adjustments creates a bias, it was concluded to exclude cost overruns in the updated methodology.

IV. Improved cost parameter set IQEF

The improved cost parameter fitting methodology optimises a cost parameter set for estimating the cost of real HVDC projects according to the improved overhead cost consideration. This is beneficial for delivering the best cost estimations for grid expansion planning purposes. The resulting new cost parameter set is called IQEF (Improved Quadruple Error Function). It corresponds to the previous QEF (Quadruple Error Function) and it is based on the same data from [6].

The new IQEF set is shown in Table IV in comparison with a few previous parameter sets. The previous sets with seven parameters were expanded to nine parameters by applying the cost ratio between SMC and UGC given in Eq. (13) in Appendix A. Figure 4 shows the performance comparison of these cost parameter sets. The new IQEF set scores best, but this is not surprising as it was optimised to do so.

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Table IV: Three cost parameter sets from [6] (adjusted to 2023 price levels, expanded to nine parameters) and the new IQEF, based on own computations

Cost parameter	—— **Cost parameter set** Q^k —— ETYS13	AVG	QEF	**IQEF**	**Unit**
$\mathcal{B}_0^k$	0.000	5.172	3.753	**2.784**	M€
$\mathcal{B}_{\text{lp,SMC}}^k$	0.301	0.994	1.009	**1.061**	M€/GW·km
$\mathcal{B}_{\text{l,SMC}}^k$	1.094	0.723	0.283	**0.248**	M€/km
$\mathcal{B}_{\text{lp,UGC}}^k$	0.376	1.243	1.262	**0.672**	M€/GW·km
$\mathcal{B}_{\text{l,UGC}}^k$	1.367	0.904	0.354	**0.408**	M€/km
$\mathcal{N}_0^k$	64.97	36.09	24.31	**22.36**	M€
$\mathcal{N}_{\text{p}}^k$	62.54	96.03	116.9	**113.5**	M€/GW
$\mathcal{S}_0^k$	147.8	67.72	59.29	**40.20**	M€
$\mathcal{S}_{\text{p}}^k$	222.8	120.3	748.3	**489.5**	M€/GW

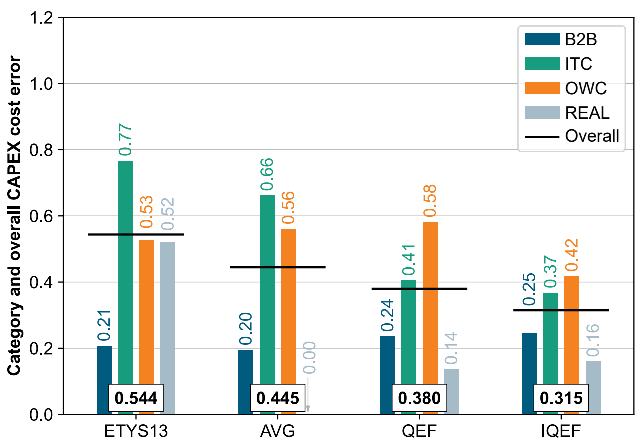

Figure 4: Performance comparison of the different cost parameter sets (Q^k), own illustration based on own computations, calculation and visualisation as explained in [6]

Note that the new IQEF set is generally *cheaper* than the old QEF set, which is primarily due to three phenomena, of which two are desired and beneficial:

- The new methodology aims explicitly at estimating the CAPEX, while the old methodology does not systematically consider overhead cost categories and investment cost levels. Ignoring these aspects resulted in the old model delivering cost figures between the *owner's CAPEX cost* and the higher *owner's project cost*.
- For the sea cost S_g^k and the corresponding cost parameters $\mathcal{S}_{\text{p}}^k$ and $\mathcal{S}_0^k$, a large difference is caused by excluding the reported cost overruns, recall Section III-B.

However, the third phenomenon leading to IQEF being cheaper is problematic. Surprisingly, UGC is fitted to be cheaper than SMC (for branches with $p_f/\omega_f > 0.41\,\text{GW}$), which is contradictory to observations of the HVDC infrastructure developments in Europe of the last decade. SMC is almost always preferred over land-based transmission if the considered transmission corridors allow both options. Examples such as the Biscay Gulf HVDC project [18] or North Sea Link project [19] indicate that high additional costs incur with land-based transmission (e.g. topography, environmental concerns, land use in densely populated areas, public opposition), which make HVDC transmission project developers choose routes at sea whenever they can.

The most reasonable explanation for UGC parameters being fitted cheaper than SMC parameters is that the data basis from [6] might be too weak for a sound fitting of these parameters. Re-applying the parameter fitting on an extended input data basis, including many new HVDC projects with significant UGC sections, will likely result in a better parameter fit. This work will be continued ... stay tuned!

V. Summary and Conclusion

The investment cost model for VSC HVDC transmission infrastructure has been improved on several aspects:

- The representation of onshore HVDC infrastructures is improved by including underground cables in a better way and excluding overhead lines.
- Considering technology progress and inflation improves the inclusion of cost data from older HVDC projects and the cost estimations of HVDC investment far in the future.
- The generalised represenation of back-to-back HVDC systems and parallel HVDC systems results in more comprehensive equations, improving user-friendliness and facilitating more complex HVDC system structures.
- The update of the maximum HVDC system power rating follows recent technological advances.

Besides improving the cost model, the developed systematic approach towards investment cost levels and overhead cost categories significantly improves the processing of input cost data from real HVDC project press releases. The cost level conversion from different cost levels to the owner's CAPEX cost (by adding or subtracting the overhead costs) provides a much better basis for comparisons as it removes some of the disturbance in the data caused by different sources publishing different cost levels. Additionally, the exclusion of previously included reported cost overruns removes an undesired bias.

All these updates lay the basis for an improved, more accurate and trustworthy fitting of the HVDC cost parameter set. The new IQEF set and the new cost model facilitate better CAPEX estimations for HVDC transmission infrastructure solutions, increasing the accuracy of transmission expansion planning activities. Note, however, that the IQEF set should not be taken as the last word on this topic. The IQEF set has been fitted using the updated methodology, but the data basis remained unchanged. Many recent HVDC projects for which cost data became available were not included in the previously fitted QEF set, and they are not covered by the IQEF set. Considering all the new data will provide a more robust basis for fitting the cost parameters. Future work will apply the updated methodology on an updated data basis, resulting in an even better VSC HVDC cost parameter set.

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Appendix

A. Formulation of the previous cost model

$$Q^k = \left\{\mathcal{B}_0^k, \mathcal{B}_{\mathrm{lp}}^k, \mathcal{B}_{\mathrm{l}}^k, \mathcal{N}_0^k, \mathcal{N}_{\mathrm{p}}^k, \mathcal{S}_0^k, \mathcal{S}_{\mathrm{p}}^k\right\} \tag{8}$$

$$C_{\mathrm{est},i}^k = \sum_{f\in F_i} B_f^k + \sum_{g\in G_i} N_g^k + \sum_{g\in \tilde{G}_i} S_g^k \tag{9}$$

$$B_f^k = \mathcal{B}_{\mathrm{lp}}^k \cdot l_f \cdot p_f + \left\lceil \frac{p_f}{\hat{P}_j^{\mathrm{old}}} \right\rceil \left(\mathcal{B}_{\mathrm{l}}^k \cdot l_f + \mathcal{B}_0^k\right) \tag{10}$$

$$N_g^k = \mathcal{N}_{\mathrm{p}}^k \cdot p_g + \left\lceil \frac{p_g}{\hat{P}_j^{\mathrm{old}}} \right\rceil \mathcal{N}_0^k \tag{11}$$

$$S_g^k = \mathcal{S}_{\mathrm{p}}^k \cdot p_g + \left\lceil \frac{p_g}{\hat{P}_j^{\mathrm{old}}} \right\rceil \mathcal{S}_0^k \tag{12}$$

$$l_f = l_{f,\mathrm{SMC}} + {}^5\!/_4 \cdot l_{f,\mathrm{UGC}} + {}^2\!/_3 \cdot l_{f,\mathrm{OHL}} \tag{13}$$

Constant	**Value**	**Explanation**
$\hat{P}_{\mathrm{B2B}}^{\mathrm{old}}$	4.0 GW	Maximum total installed converter power rating for single B2B HVDC system
$\hat{P}_{\mathrm{ITC}}^{\mathrm{old}}$	2.0 GW	Maximum total installed converter power rating for single ITC HVDC system
$\hat{P}_{\mathrm{OWC}}^{\mathrm{old}}$	2.0 GW	Maximum total installed converter power rating for single OWC HVDC system