Transmission Corridor between Romania-Moldova-Ukraine

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***Abstract* – Constructed in 1986, the 750 kV line connecting the Ukrainian and Romanian transmission networks went out of service in the mid-1990s due to damage to the lines. Although the Romanian TSO (Transelectrica) and the Ukrainian TSO (Ukrenergo) carry plans to restore the line, each has experienced significant development of their transmission networks since the line went out of service. This article identifies the optimal configuration of the corridor to serve the transmission requirements of the system operators in Romania, Ukraine and Moldova. Currently the transmission corridor, which had consisted of a 750kV AC Over Head Line (OHL), is not in operation and is in a state that cannot be easily repaired. The OHL has been damaged so that it could be considered as "non-existent" for each party. The investment scenarios themselves are comprised two voltage levels considered for the corridor: 400 kV and 750 KV. In turn, these voltages can be analyzed in terms of synchronous AC or asynchronous DC connection via a back-to-back station that may be located in either Moldova or Romania.**

Keywords: asynchronous, back-to-back, IPS/UPS, RUM

I. INTRODUCTION

Currently the Romanian – Moldovan – Ukrainian (RUM) transmission corridor, which had consisted of a 750kV AC Over Head Line (OHL), is not in operation and is in a state that cannot be easily repaired. The OHL has been damaged so that it could be considered as "non-existent" for each RUM party. The existing route of the old 750 kV transmission line is depicted in Fig.1.

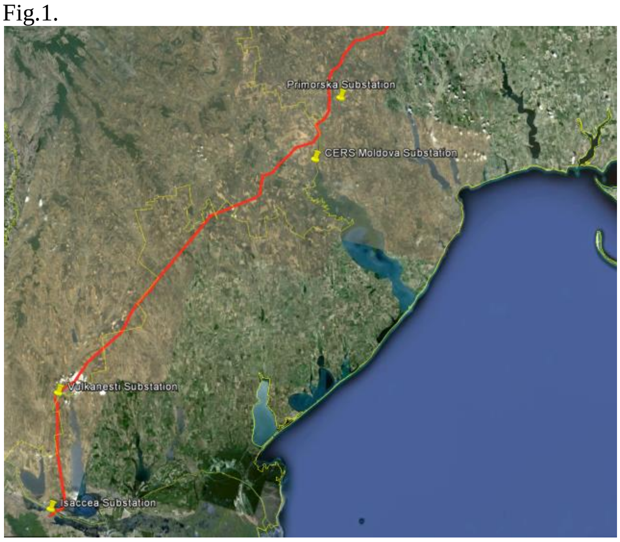

Fig. 1. The route of the old 750 kV transmission line

Although the original transmission corridor is directly between Pivdennoukrainska NPP (Ukraine) and Isaccea (ROM) Substations, Ukraine plans to construct a new 750kV OHL between Pivdennoukrainska NPP and Primorska Substation (see red dashed line in Fig.2). Hence, the corridor under discussion in this article will cover the existing Right of Way between Primorska (Ukraine)-Isaccea (ROM) substations. This corridor is depicted in Fig.2 (blue dashed line).

The transmission line distances between the substations in the corridor are provided in Table 1. The transmission lengths do not represent fly-over distances but rather the total line lengths assumed in the analysis, which were vetted by the participating TSO.

Fig. 2. RUM transmission corridor (dashed blue line)

Table 1. Transmission line distances between the substations.

Expected OHL Distances (km)		From Substation			
		Primorska	CERS Moldova	Vulcaneşti	Isaccea
To Substation	Primorska	-	50	200	260
	CERS Moldova	50	-	175	235
	Vulcaneşti	200	175	-	60
	Isaccea	260	235	60	-

The possible connection points (i.e., candidates) in Moldova are: 400 kV CERS Moldova and Vulcanesti Substations. Summary of the substations along the RUM transmission with the corresponding voltage levels are given in Table 2.

Table 2. Summary of the substations along the RUM transmission corridor.

Country	Substation	Abbreviation	Existing EH Voltage Level in Substations		
			750kV	400kV	330kV
Ukraine	Primorska	UKR	✓	✗	✓
Moldova	CERS Moldova	MDV_1	✗	✓	✓
Moldova	Vulcaneşti	MDV_2	✗	✓	✗
Romania	Isaccea	ROM	✓	✓	✗

Considering the candidate substations in Moldova and the available voltage levels, three groups of variants are generated as alternatives for the investigations, as presented in Table 3.

Table 3. Substation and voltage level variants to be investigated.

Seasonal Variants	Substation Variants	Voltage Level Variants	Connection Type Variants
Summer Peak Load	UKR - ROM	1 x 750 kV	AC OHL
Summer Min Load	UKR - MDV_1 - ROM	2 x 400 kV	DC B2B (located at ROM)
Winter Peak Load	UKR - MDV_2 - ROM	1 x 400 kV	DC B2B (located at first SS before ROM)
	UKR - MDV_1 - MDV_2 - ROM		

Initial assumption, was to analyze a total of 36 scenarios (Substation Variants (4) x Voltage Level Variants (3) x Seasonal Variants (3) = 36) as given in Table 3. However, the initial analysis indicated a strong dependency of results to “Connection Type Variants”. Hence “Connection Type Variants” are also included in the analysis creating a total of 108 scenarios (108 = 36 x 3 (Connection Type Variants)) to be analyzed.

II. METHODOLOGY

The approach in load flow and N-1 contingency analysis will be to search for the maximum amount of power that can be transferred safely from/to Ukraine+Moldova to/from Romania, for each combination of Substation and Voltage Level Variants shown in Table 3. Flowchart of this approach (i.e., algorithm) is given in Fig. 3.

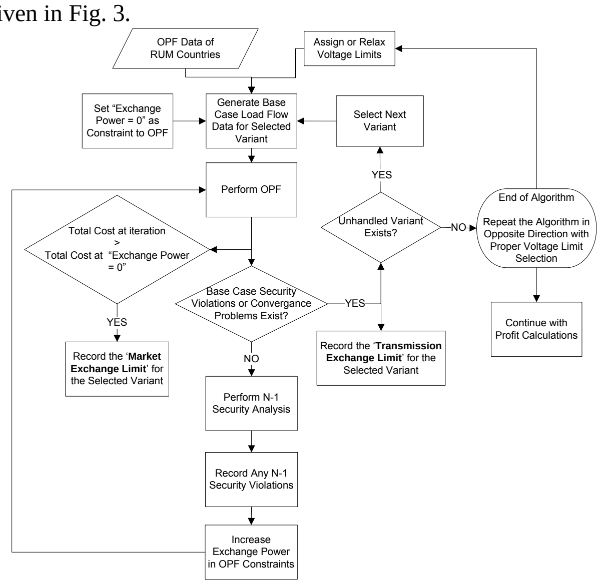

Fig. 3. Flow Chart of the methodology (OPF and N-1 contingency analysis)

The reasoning behind “Assign or Relax Voltage Limits” block can be described as follows: The OPF solution has the ability to assign voltage constraints for individual buses. At the data collection phase, the voltage level limits for each RUM party is collected for high voltage network as given in Table 4.

Table 4. Voltage level limits for analysis.

Country	Voltage Level				
	750kV	500kV	400kV	330kV	220kV
Romaina	+/-5%	-	+/-5%	-	+/-10%
Ukraine	+/-5%	+/-5%	+/-5%	+/-10%	+/-10%
Moldova	+/-5%*	-	+/-5%	+10% / -5%	-

Voltage constraints are indeed local problems that can be assumed to be handled by proper operational maneuvers in the short term (e.g., proper selection of generator voltage set points) and relatively easy capacitor/reactor investments in the mid-term. The economical calculations (i.e., cost/benefit analysis) based on the results with voltage constraints might be misleading since such voltage problems can be solved either with reasonable investments in a plausible time frame or with operational maneuvers in real time). Hence, for long term decision making analysis, it is more reasonable to work with OPF results performed ignoring local voltage constraints. Nevertheless, the OPF and contingency analysis are performed and results are recorded for both considering and ignoring the voltage constraints. The effect of voltage constraints on total generation cost and optimum power exchange amounts in Scenario 1 is illustrated in Fig. 4, as an example.

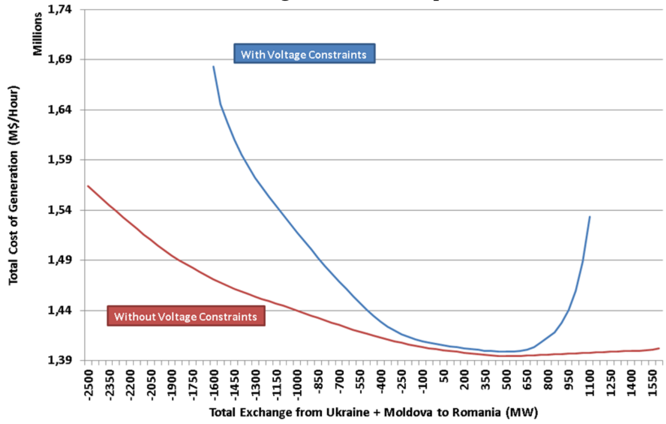

Fig. 4. Total generation cost results of Scenario 1 (with and without voltage constraints).

As illustrated in Fig. 4, the OPF algorithm forces the solution to a higher cost in order to be able to satisfy the voltage constraints. The effect is more observable as the exchange approaches higher values at both directions. However, as the voltage constraints are relaxed, the cost reduces as OPF does not consider voltage constraints. The algorithm of the methodology in Fig. 3 starts from an N-secure case with zero exchanges and iteratively increases the exchange power through the RUM corridor in order to find the optimum power exchange between the parties. The algorithm repeats the followings iteratively:

- Assigns an exchange from/to Ukraine+Moldova to/from Romania as a constraint to OPF,
- Performs an OPF to determine the dispatching,
- Compare total generation cost with zero power exchange case in order to determine the realistic transaction limit due to price difference,
- Creates a load flow scenario based on OPF solution,
- Performs N-1 contingency analysis,
- Records the N-1 security violations of each scenario, if any.
- Power exchange is increased in 50 MW steps.
- The analysis performed with and without voltage constraints and the results are compared.

Trading scenarios between RUM countries, as predicted by each party, are given in Table 5. The trading amounts presented in this table are utilized as “indicative” parameters in the analysis. As described above, the approach in OPF analysis is to search for the “maximum” amount of power that can be transferred N-securely between the RUM countries for each scenario that are shown in Table 3. In other words, the algorithm given in Fig. 3 will give the upper limit (i.e., maximum) for the N-secure power trading among RUM countries. The upper limit for the N-secure power trading could be less or more than the corresponding indicative power transfer amounts that are shown in Table 5 (last column).

Table 5. Trading scenarios initially predicted by RUM parties.

Scenarios	Import from	Export to	Transfer
1	Ukraine and/or Moldova (U&M: Synchronized with IPS/UPS)	Romania (R: Island with IPS/UPS)	200 MW
2	Ukraine and/or Moldova (U&M: Synchronized with IPS/UPS)	Romania (through HVDC B2B) (location of HVDC B2B to be analysed)	500 MW
3	Moldova (through direction of generator Moldavska to Romania)	Romania	480 MW
4	Ukraine and/or Moldova (U&M: Synchronized with IPS/UPS)	ENTSO/E (through Romania) (through HVDC B2B) (location of HVDC B2B to be analysed) (Max export of Moldova = 500 MW)	1500 MW
5	Moldova (through direction of generator Moldavska to Romania)	Romania	480 MW
6	Ukraine and/or Moldova (U&M: Synchronized with ENTSO/E)	ENTSO/E (through Romania) (Max export of Moldova = 500 MW)	1500 MW
7	Ukraine and/or Moldova (U&M: Synchronized with IPS/UPS)	ENTSO/E (through Romania) (through HVDC B2B) (location of HVDC B2B to be analysed) (Max export of Moldova = 500 MW)	1500 MW
8	Ukraine and/or Moldova (U&M: Synchronized with ENTSO/E)	ENTSO/E (through Romania) (Max export of Moldova = 500 MW)	1500 MW
9	Romania Romania (R: Island with IPS/UPS)	Ukraine Moldova (U&M: Synchronized with IPS/UPS)	400 MW 100 MW
10	Romania Romania Romania	ENTSO/E Ukraine Moldova (U&M: Synchronized with ENTSO/E)	1500 MW 400 MW 100 MW
11	Romania Romania Romania	ENTSO/E Ukraine Moldova (To U&M through HVDC B2B) (location of HVDC B2B to be analysed)	1500 MW 400 MW 100 MW

III. COST/BENEFIT ANALYSES

The OPF analyses cover the largest part of the analysis and create a basis for the cost/benefit analysis which is described in this section. In this section, performance indicators for economic and financial analysis, determination of necessary investments for the corresponding investment scenarios, and calculation of per unit investment and operation and maintenance costs are described.

III.1. Performance Indicators (IRR, NPV, and B/C Ratio)

The economic and financial analysis is based on the results of the OPF analysis, which calculates the total savings to region at the optimum power exchange in each loading hour (i.e., winter max, summer max, and summer min). The Cost/benefit analysis was made by comparing the results of the OPF analysis with the investment cost (Inv cost) and operational and maintenance costs (O&M cost) of the candidate investments.

For each scenario, annual cash flow tables for 30 years were determined to conduct the following analyses:

- Internal rate of return (IRR) analysis,
- Net present value (NPV) analysis,
- Benefit/Cost ratio (B/C ratio) analysis.

A 30 year useful life of equipment was assumed for the purposes of the economic/financial calculations. The following parameters (KEPs) were utilized:

- Interest rate of borrowing money for total investment cost
- Loan period
- Discount rate for calculating NPVs

The costs of each investment scenario includes:

- Total investment cost (TIC) at the initial year (USD),
- Annual O&M cost (USD/year).

As described below, annualized savings are considered in the economic and financial analysis. As described in Section 9, sensitivity analyses were performed for the key economic parameters including both AWFs and different generation levels of wind power plants in Romania.

The year 2012 is considered to be the base year in unit costs of the equipment. The annual cash flow table is provided in Table 6.

It should be noted that annual savings can be negative in some investment scenarios that correspond to the most constrained loading conditions (e.g., winter max), even during zero exchange among the countries. This can occur when voltage constraints combine with high technical losses, and higher generation levels of the most costly power plants in the RUM countries than might be dispatched if there was no interconnection between the RUM countries. The total saving is assumed to be zero in such cases because the RUM transmission corridor circuit can be opened to curtail electricity flow in such circumstances.

Table 6. Annual cash flow table of each scenario.

Year	Cost (USD/year)	Saving (USD/year)	Balance (USD/year)
Year 0	Inv cost	0	– (Annual loan payback)
Year 1	Annual O&M cost	Annual Saving	+ (Annual Saving) – (Annual loan payback + O&M cost)
Year 2	Annual O&M cost	Annual Saving	+ (Cumulative Annual Saving) – (Annual loan payback + Cumulative O&M cost)
...	...	...	...
Year 30	Annual O&M cost	Annual Saving	+ (Cumulative Annual Saving) – (Annual loan payback + Cumulative O&M cost)

In the LF and OPF analysis, the maximum savings in each scenario are determined at three loading hours along the year (i.e., winter max, summer max, and summer min loading hours). The savings at these loading hours are utilized in determining the annual average savings (i.e., annualization of the savings). Annualization of the savings is based on the annualized weighting factors (AWF) of these three loading hours.

The regional system coincident annual hourly load recordings for 2010 were utilized to determine the AWFs. Annual hourly coincident regional load and its distribution along one year are given in Fig. 5 and Fig. 6, respectively. The following loading hours are indicated in the figures:

- System peak (i.e., winter max)
- System off-peak (i.e., summer min)
- System peak during off-peak season (i.e., summer max)

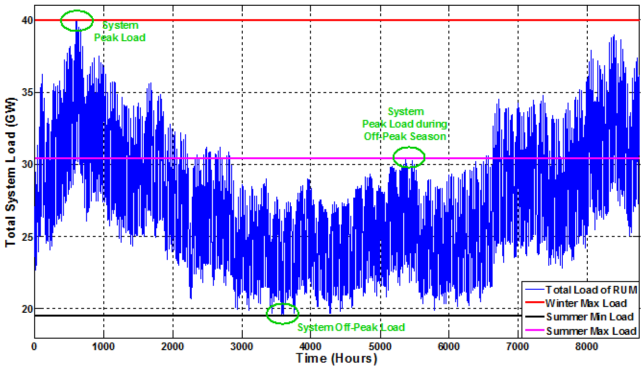

Fig. 5. Annual hourly coincident system load

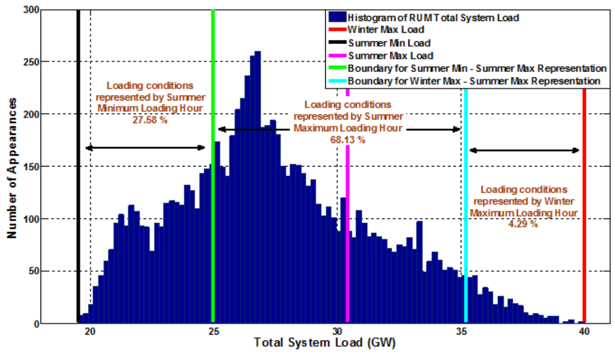

Fig. 5. Distribution of the hourly loads along the year.

AWFs of these three loading hours are indicated in Fig. 6 and summarized in Table 7. Note that, total energy consumed along the year (the area below the blue curve in Fig. 5) is equal to (1):

4,29%(System peak) + 27,58%*(System off-peak) + 68,13%*(System peak during off-peak season)* (1)

Table 7. AWFs assumed for RUM countries.

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Loading condition	Loading hour	AWFs
System peak	Winter max	4,29%
System off-peak	Summer min	27,58%
System peak during off-peak season	Summer max	68,13%

This approach is analyzed below for the following parameter and investment scenario (Case_VC-I_W30%):

- Investment Scenario No: 1
  - 1x400kV Ukraine-MDV_2-ROM (connection through HVDC B2B substation at Romania)
- Wind generation level at Romania: 30%
- Voltage constraints: Ignored
- Loading Scenarios:
  - Scenario 4: System peak (Winter max)
  - Scenario 3: System off-peak (Summer min)
  - Scenario 2: System peak during off-peak season (Summer max)

The savings which are determined by OPF analyses for the three loading scenarios are given in Table 8.

Table 8. Annualization of savings for the Scenarios 2,3 and 4

Loading hour	Savings (USD/h)	Weighting factor (%)	Annualized average saving (USD/h)	Unavailability* of the line along the year (h)	Annual saving (USD/year)
Winter max (Scenario 107)	A = 8.916,25	4,29%	A * 4,29% + B * 27,58% + C * 68,13% = 5.238,68	5% * 8760 h = 438 h	5.238,68 *(8760-438) = 43.596.276,03
Summer min (Scenario 95)	B = 3.635,13	27,58%			
Summer max (Scenario 83)	C = 5.656,25	68,13%			

As illustrated in the table:

- The maximum saving occurs at “system peak” (i.e., winter max).
  - The room for OPF is maximum given high generation levels of cost-ineffective power plants in the region.
- The minimum saving occurs at “system off-peak” (i.e., summer min).
  - The potential for optimization is minimal due to system constraints at minimum loading conditions
  - The availability of cost effective generator capacity in the system is minimum.
- In order to determine the annualized total saving, availability of the line should be estimated (downtime for maintenance and unavailability of the line due to faults must be estimated). An availability of 8322 hours, which corresponds to ≈95% of the hours in a year, is assumed for the economic/financial analysis.
- Annual saving for this investment scenario is calculated as 43.596.276,03 USD/year, as illustrated in Table 8.

This approach was employed in for investment scenarios to in determine the annualized savings for cost/benefit analysis.

III.2. Necessary Investments and Corresponding Costs

This section reviews the approach to determining the total amount of equipment that should be installed to support each investment scenario. The following assumptions are made:

- Each substation was equipped with a spare bay at the corresponding voltage level, in case of emergency/maintenance/etc.;
- 750/400 kV or 750/330 kV transformers at the corresponding substations to satisfy n-1 reliability criteria;
- In the scenarios in which there are two substations in Moldova, there will be only one transformer in each substation. This meant that n-1 contingency was satisfied by the transformer in the other substation; and
- As the intermediary substations in the corridor, the new substations in Moldova were assumed to have additional bays- the total number of which depends on the connection type.

The determination of the necessary equipment for different investment scenarios is described in the following subsections.

III.2.1. Ukraine – Romania (1x750 kV AC)

In this investment scenario, the following investments are assumed in Ukraine and Romania:

- Primorska/Ukraine:
  - Two 750/330 kV transformers (1250 MVA)
  - Four 750 kV bay:
    - One for the transmission line;
    - Two for the connection of transformers; and
    - One for spare.
  - Three 330 kV bay:
    - Two for the connection of transformers; and
    - One for spare.
- Isaccea/ Romania:
  - Two 750/400 kV transformers (1250 MVA).
  - Four 750 kV bay:
    - One for the transmission line;
    - Two for the connection of transformers; and
    - One for spare.
  - Three 400 kV bay:
    - Two for the connection of transformers; and
    - One for spare.

The necessary equipment is summarized in Table 9 below.

Table 9. Total amount of equipment necessary for Scenario 1.

Scenario	Transmission Corridor	Voltage Level
1	UKR - ROM	1 x 750kV
		# of equipment
Primorska	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/330 kV power transformer	2
	330 kV bay for power transformers	2
	330 kV spare bay	1
	Total 750 kV bay	**4**
	Total 330 kV bay	**3**
	Total 750/330 kV power transformers	**2**
Isaccea	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	2
	400 kV bay for power transformers	2
	400 kV spare bay	1
	Total 750 kV bay	**4**
	Total 400 kV bay	**3**
	Total 750/400 kV power transformers	**2**

III.2.2. Ukraine – Moldova_1 - Romania (1x750 kV AC)

- Primorska/ Ukraine:
  - Two 750/330 kV transformers (1250 MVA)
  - Four 750 kV bay:
    - One for the transmission line;
    - Two for the connection of transformers; and

        - One for spare.
    - Three 330 kV bay:
        - Two for the connection of transformers; and
        - One for spare.
- CERS Moldova/Moldova:
    - Two 750/400 kV transformers (1250 MVA).
    - Five 750 kV bay:
        - One for the transmission line input;
        - One for the transmission line output;
        - Two for the connection of transformers; and
        - One for spare.
    - Three 400 kV bay:
        - Two for the connection of transformers; and
        - One for spare.
- Isaccea/Romania:
    - Two 750/400 kV transformers (1250 MVA).
    - Four 750 kV bay:
        - One for the transmission line;
        - Two for the connection of transformers; and
        - One for spare.
    - Three 400 kV bay:
        - Two for the connection of transformers; and
        - One for spare.

The necessary equipment is summarized in Table 10 below.

Table 10. Total amount of equipment necessary for Scenario 2.

Scenario	Transmission Corridor	Voltage Level
2	UKR - MDV_1 - ROM	1 x 750kV
Primorska	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/330 kV power transformer	2
	330 kV bay for power transformers	2
	330 kV spare bay	1
	Total 750 kV bay	4
	Total 330 kV bay	3
	Total 750/330 kV power transformers	2
CERS Moldova	750 kV bay for transmission line to RUM	2
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	2
	400 kV bay for power transformers	2
	400 kV spare bay	1
	Total 750 kV bay	5
	Total 400 kV bay	3
	Total 750/400 kV power transformers	2
Isaccea	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	2
	400 kV bay for power transformers	2
	400 kV spare bay	1
	Total 750 kV bay	4
	Total 400 kV bay	3
	Total 750/400 kV power transformers	2

III.2.3. UKRAINE – MOLDOVA_1 – MOLDOVA _2 - ROMANIA (1X750 KV)

- Primorska/Ukraine:
    - Two 750/330 kV transformers (1250 MVA).
    - Four 750 kV bay:
        - One for the transmission line;
        - Two for the connection of transformers; and
        - One for spare.
    - Three 330 kV bay:
        - Two for the connection of transformers; and
        - One for spare.
- CERS Moldova/Moldova:
    - One 750/400 kV transformer (1250 MVA).
    - Four 750 kV bay:
        - One for the transmission line input;
        - One for the transmission line output;
        - One for the connection of transformers; and
        - One for spare.
    - Two 400 kV bay:
        - One for the connection of transformer; and
        - One for spare.
- Vulcanesti/Moldova:
    - One 750/400 kV transformer (1250 MVA).
    - Four 750 kV bay:
        - One for the transmission line input;
        - One for the transmission line output;
        - One for the connection of transformer; and
        - One for spare.
    - Two 400 kV bay:
        - One for the connection of transformers; and
        - One for spare.
- Isaccea/Romania:
    - Two 750/400 kV transformers (1250 MVA).
    - Four 750 kV bay:
        - One for the transmission line;
        - Two for the connection of transformers; and
        - One for spare.
    - Three 400 kV bay:
        - Two for the connection of transformers; and
        - One for spare.

The necessary equipment is summarized in Table 11 below.

Table 11. Total amount of equipment necessary for Scenario 4.

Scenario	Transmission Corridor	Voltage Level
4	UKR - MDV_1 - MDV_2 - ROM	1 x 750kV
Primorska	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/330 kV power transformer	2
	330 kV bay for power transformers	2
	330 kV spare bay	1
	Total 750 kV bay	4
	Total 330 kV bay	3
	Total 750/330 kV power transformers	2
CERS Moldova	750 kV bay for transmission line to RUM	2
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	1
	400 kV bay for power transformers	1
	400 kV spare bay	1
	Total 750 kV bay	4
	Total 400 kV bay	2
	Total 750/400 kV power transformers	1
Vulcaneşti	750 kV bay for transmission line to RUM	2
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	1
	400 kV bay for power transformers	1
	400 kV spare bay	1
	Total 750 kV bay	4
	Total 400 kV bay	2
	Total 750/400 kV power transformers	1
Isaccea	750 kV bay for transmission line to RUM	1
	750 kV spare bay for RUM	1
	750 kV bay for 750/400 kV power transformer	2
	400 kV bay for power transformers	2
	400 kV spare bay	1
	Total 750 kV bay	4
	Total 400 kV bay	3
	Total 750/400 kV power transformers	2

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IV. HVDC BACK TO BACK CONNECTION ANALYSES

In this section, first the challenges with the HVAC interconnection of ENTSO-E and IPS/UPS systems are discussed. Then, the analysis for the HVDC interconnections of RUM Countries is presented. Romania is connected to the ENTSO-E system, whereas Ukraine and Moldova are connected with IPS/UPS network as shown in Fig.6.

Fig.6. ENTSO-E and IPS/UPS systems at the RUM countries' area

Following the EU-Russia energy dialogue, an extensive study was launched in 2004 under UCTE guidance with the aim of identifying the technical and operational preconditions for the interconnection of the two largest European power systems – UCTE (now ENTSO-E) and IPS/UPS. The possibility of the interconnection of the two systems, which would allow for direct technical and commercial cooperation in the field of electric power, was investigated. Particular attention was devoted to stability of interconnected networks, the prevention of crisis situations and the legal aspects of such interconnected operation. The results of the study proved the technical possibility of such interconnection, but concluded that the investment required to operate the system in a secure and stable manner were prohibitive.

Given the cost and technical challenges associated with AC connection of the ENTSO-E and IPS/UPS networks, HVDC back-to-back technology interconnection of the RUM countries was considered as a variant for the short/mid-terms.

V. HVDC BACK TO BACK TECHNOLOGIES

There are two primary HVDC Back to Back technologies: Line Commutated Converter (LCC) and Voltage Source Converter (VSC). HVDC Back to Back substations based on conventional Line Commutated Converter (LCC) technology depend on the Short Circuit MVA (SCMVA) at the connection point to the grid. The new VSC technology substations can operate independent from the SCMVA at the connection point. Today, both technologies are being deployed

The chronological development of the two HVDC technologies is given in Fig.7.

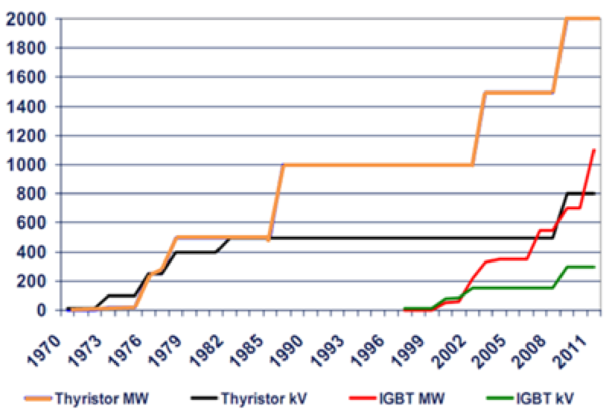

Fig.7. Chronological development in LCC and VSC technologies

While thyristors are utilized in conventional LCCs, (see Fig.8.), VSCs employ IGBTs (see Fig.9.). This make the unit cost of VSC based technology higher than that of LCC, as illustrated in Table 12.

Table 12. Cost comparison of LCC and VSC technologies (equipment only). [1]

LCC Technology	VSC Technology
0.08 Euro/VA	0,11 Euro/VA

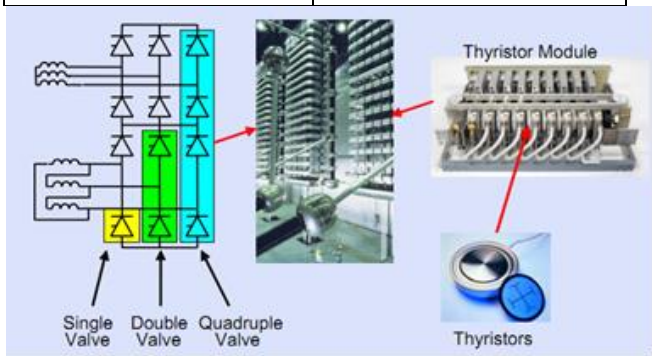

Fig. 8. Line Commutated Converter (LCC).

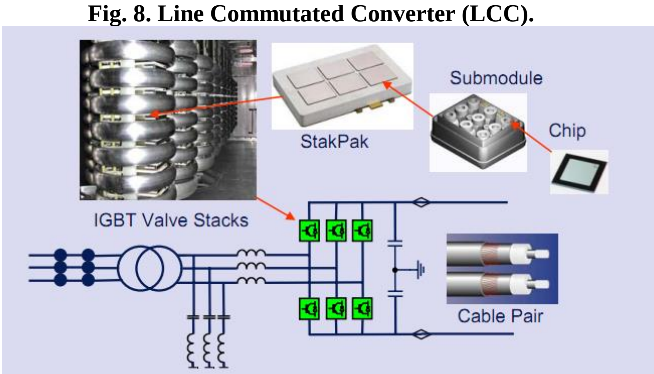

Fig.9. Voltage Source Converter (VSC).

V.1. Requirement of Harmonic Filters

LCC based HVDC Back to Back substations generally require harmonic filters with a capacity of almost 60% of the substation [2]. For example, for a 300 MW block substation, the capacity of the necessary harmonic filters is 300*0.6 = 180 MVar.

V.2 ESCR Criteria

The results of the ESCR calculation results are presented in this section to determine the acceptable level of the LCC technology based HVDC Back to Back substations.

$$ESCR = \frac{SCMVA_{grid} - S_{filter}}{P_{dc}} \qquad (2)$$

In this formula, the contribution of the filters to SCMVA is subtracted to consider the true SCMVA of the grid. In this article, HVDC Back to Back connection is modelled by splitting the networks at the point of HVDC connection and introducing POSITIVE and NEGATIVE loads at appropriate sides. The schematic representation of such modelling is illustrated in Fig.7. As seen in the figure, the power flow through HVDC Back to Back substation from Primorska to Isaccea is modelled by splitting the networks and introducing a POSITIVE Load at Primorska side and a NEGATIVE Load at Isaccea side. It should be noted that a NEGATIVE Load is preferred in representing power injection rather than modelling a generator, in order to avoid unrealistic reactive support from the HVDC Back to Back via the generator. Given this representation, the SCMVA contribution of the HVDC Back to Back filters is not considered in the load flow and short circuit analysis. Therefore, the ESCR should be calculated as in (3).

$$ESCR = \frac{SCMVA_{grid}}{P_{dc}} \quad (3)$$

For the secure operation of HVDC Back to Back substation that is based on LCC the

$$ESCR \geq 3 \text{ (base case) [3]} \quad (4)$$

Essentially, the ESCR is different at each connection point of the HVDC Back to Back substations given different topologies. For the sake of security, the minimum value among the SCMVA at each connection point is considered in calculating of the ESCRs. The available HVDC Back to Back substation capacity is calculated assuming that total capacity of the substation is formed by 300 MW blocks, while taking into account the ESCR criteria (4).

V.3 Determination of Total Capacity of HVDC Back to Back Substation

It is assumed that the HVDC Back to Back substation blocks will be in the order of 300 MW capacities. The following arguments support this approach:

- 300 MW capacity HVDC Back to Back substations are available in the market.
- The order of 300 MW is plausible to match the optimum substation capacity with the optimum power exchange amounts that are determined in LF (Load Flow) and OPF (Optimal Power Flow) analysis.

For example, the approach in determining the total capacity of the HVDC Back to Back substation is presented below (1x400 kV transmission line between Ukraine - Romania through HVDC Back to Back substation in Ukraine):

- Loading condition of the scenario: Summer maximum.
- Wind generation level in Romania: Normal (i.e., generation level of the wind power plants in Dubrudja/ROM region is 30% of the capacity).
- OPF results at base case (i.e., ignoring N-1 contingency):
  - 700 MW (Ukraine => Romania)
- N-1 security exchange technical limit:
  - 1.300 MW (Ukraine => Romania)
  - Since 700 < 1300, 700 MW power exchange is feasible in the sense of N-1 security concern.
- Voltage collapse power exchange limit:
  - 1.500 MW (Ukraine => Romania)
  - Since 700 < 1.500, 700 MW power exchange is feasible in the sense of voltage collapse concern.
- Assuming that HVDC Back to Back substation is composed of 300 MW blocks, total number of block to realize 700 MW power exchange is three (3*300 = 900 > 700)
  - Total capacity of the HVDC BACK TO BACK substation is 900 MW.
- ESCR criteria:
  - Maximum SCMVA of the grid at the HVDC Back to Back substation is calculated as 2.063 MVA
  - ESCR = 2.063/900 = 2,29
  - Since 2,29 < 3, total capacity of 900 MW is NOT acceptable in the sense of ESCR criteria.
  - If one block among the three blocks is removed, then the total capacity of the substation is 2x300 = 600 MW
    - ESCR = 2.063/600 = 3,43 > 3 => acceptable

An HVDC Back to Back capacity of 600 MW is proven in the summer maximum loading conditions. Similar analyses were performed for winter maximum and summer minimum loading conditions, as well. The total capacity of the HVDC Back to Back substation is considered to be the maximum capacity determined among three loading scenarios. This approach is considered in all scenarios that include HVDC Back to Back substation.

VI. CONCLUSIONS

Voltage constraints were local problems that could be resolved through network operations in the short term (e.g., proper selection of generator voltage set points) and relatively inexpensive capacitor/reactor investments in the mid-term. Hence, voltage constraints are ignored in certain cases to determine the maximum volume of power exchange among the countries. The maximum voltage deviation at the key nodes was observed to be +/-20%, which could be resolved by proper compensation through the provision of additional reactors.

The increase in wind generation in Romania dramatically limited the ability of the RUM countries to optimize the regional generation fleet based on the cost of production. In some investment scenarios, the flow of power changed direction from north → south to south → north when the wind power plant generation in Romania increased from 30% to 70% and it is designated as must run. This occurs when the OPF algorithm forced inefficient high cost generators, first in Romania and then in Moldova and Ukraine, to reduce their generation in favor of must run wind. This process continued until the reduction of generation in Ukraine and Moldova became so much more cost effective than the reduction of generation in Romania that the power flow changed direction. From this point onward, Romania began exporting power in a northward direction to Moldova and Ukraine.

It is important to note that for the investment scenario of a 400 kV connection passing through a HVDC B2B substation, the benefit/cost ratio was > 1, when Romanian must run wind generation was modeled with a 30% capacity factor.

Connection through the HVDC Back to Back was superior to connection through AC options in almost every investment scenario considered. This was because the HVDC connection reduced technical network constraints to increase power exchange, enlarging the scope for power flows in the sub-region.

In fact, HVDC B2B was the only investment solution which resulted in benefit/cost > 1 when considering the scenario of Romanian must run operating with a 30% capacity factor. And, the technical challenges to synchronizing the current IPS/UPS and ENTSO-E members of the RUM working group would inhibit interconnection via high voltage AC interconnections for the foreseeable future. Therefore, HVDC technology based interconnection of the RUM countries seemed the most rational solution in the short/mid-term.

There was no significant difference revealed in the cost/benefit analyses for the different investment scenarios related to the configuration of the corridor, i.e., either directly from Ukraine to Romania or through Moldova. If the interconnection between RUM countries were realized in intermediate steps, (for example, if the connection between Romania and Moldova were realized before all three countries are interconnected), energy trade between Romania and Moldova could begin before the trading among all three countries by directing a generator in Moldova to operate synchronously with Romania in island mode.

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