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Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation

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Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation

Given the increase in renewable generation in recent years, it has become increasingly important to understand the manner in which operational challenges arising from intermittency may be mitigated with other technologies or operating procedures. One such technology is high-voltage direct current (HVDC) transmission lines. To help better inform the U.S. Energy Information Administration's (EIA) long-term planning models and projections, EIA commissioned a study from ICF Incorporated, LLC (ICF) to assess the role that HVDC transmission lines may play as additional renewable generation sources become integrated into electrical grids.

More specifically, ICF was asked to review the extent to which they believed HVDC lines may mitigate challenges resulting from additional renewable generation, the advantages and disadvantages of using HVDC lines to transmit the electricity generated from renewable sources, and the potential costs of constructing additional HVDC lines in a formal analysis based on many sources of information.

To provide some background, electricity generated by renewable resources can be categorized into two types—dispatchable and non-dispatchable generation. Dispatchable generation sources include conventional hydroelectric, geothermal, and biomass. Non-dispatchable (or intermittent or variable) generation sources like solar and wind, however, depend on the resource availability, such as when the sun is shining or the wind is blowing. As a result, these technologies have limited capability to respond to generation dispatch signals.

The increasing deployment and penetration of non-dispatchable renewable generation from resources like solar and wind can lead to electrical system operational issues, which include under- or over-generation during times of high or low electricity demand. Such conditions could potentially require additional grid services to accommodate the associated fluctuations in generation delivered from these resources.

Power transmission lines facilitate the bulk transfer of electricity from a generating station to a local distribution network. The U.S. electric transmission network consists of around 700,000 circuit miles of lines. Most of these lines operate with alternating current, which is how power is typically generated and delivered to the end-use customers.

HVDC lines have typically been used to transfer large amounts of power over long distances. They are now being proposed as a way to move electricity generated from wind in high-quality wind resource regions to other parts of the country. If properly configured, direct current transmission could also help mitigate operational issues with wind and solar generation such as a mismatch in generation in relation to the need for increased ancillary services associated with renewable generation. This can be accomplished by effectively moving electricity generated from wind or solar resources from areas of high penetration to areas with lower penetration.

It should be noted that challenges associated with increased penetration of generation from wind and solar resources may also be mitigated using a variety of other technologies or practices, including smart grid technologies, energy storage, or other flexible generating technologies. However, the role that HVDC lines may play in mitigating some of the potential challenges imposed by the growth in non-dispatchable renewable generation on electric grids is an important consideration.

APPENDIX

Assessment of the Potential for High-Voltage Direct Current Transmission to Mitigate Impacts of Non-Dispatchable Generation Technologies

FINAL REPORT

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Submitted to:
United States Energy Information Administration (EIA)
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Submitted by:
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List of Abbreviations, Acronyms, and Initialisms

AC	Alternating current
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCC	Capacitor-commutated converter
CFE	Comisión Federal de Electricidad
CIGRE	Council on Large Electric Systems
CREZ	Competitive Renewable Energy Zone
DC	Direct current
DIR	Dispatchable intermittent resource
DOE	Department of Energy
EI	Eastern Interconnect
EIM	Energy Imbalance Market
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electricity Reliability Council of Texas
ETSAP	Energy Technology Systems Analysis Programme
FCA	Forward capacity auction
FERC	Federal Energy Regulatory Commission
FOSG	Friends of Supergrid
FRT	Fault ride through
GTO	Gate turn-off
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
HTP	Hudson Transmission Project
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated-gate bipolar transistor
IGCT	Integrated gate-commutated thyristor
IOU	Investor-owned utility
IRENA	International Renewable Energy Agency

List of Abbreviations, Acronyms, and Initialisms

ISO-NE	Independent System Operator – New England
JEDI	Jobs and Economic Development Impact
LADWP	Los Angeles Department of Water and Power
LCC	Line-commutated converter
LCOE	Levelized cost of energy
MI	Mass impregnated
MISO	Midcontinent Independent System Operator
MMC	Modular multilevel converter
MVP	Multi-value projects
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
PES	Power & Energy Society
PMU	Phasor measurement unit
QTR	Quadrennial Technology Review
RMS	Root-mean square
ROW	Right-of-way
RPS	Renewable portfolio standard
SPP	Southwest Power Pool
TSO	Transmission system operator
TVA	Tennessee Valley Authority
TWE	TransWest Express
UHVDC	Ultra-high-voltage direct current
VER	Variable energy resource
VSC	Voltage-source converter
WECC	Western Electricity Coordinating Council
XLPE	Cross-linked polyethylene

1. Summary of Findings

Worldwide, there has been a renewed resurgence and interest in developing high-voltage direct current (HVDC) transmission projects for economic interregional transfer of electric power (Patel 2017). In the United States, several HVDC projects are in the planning pipeline to facilitate integration of renewable resources in remote host regions to distant load centers. This study examines the role of HVDC lines in mitigating the impacts of non-dispatchable renewable generation technologies. Non-dispatchable technologies (or intermittent or variable generation technologies), like solar and wind, operate based on resource availability, thereby creating dispatchability challenges for system operators. The report addresses a number of specific questions raised by the U.S. Energy Information Administration (EIA) designed to examine the circumstances under which HVDC lines play a role in integrating renewables, the extent to which HVDC lines can mitigate the impact of non-dispatchable renewable generation, the configurations of HVDC suited for renewable integration, potential grid issues in using HVDC lines for renewables integration, and the potential costs of constructing these lines based on experiences to date.

This study is based on a three-pronged approach. First, ICF reviewed several publicly available sources to assess the suitability of HVDC technology in addressing grid integration issues related to the development of renewable energy. Second, ICF compiled and summarized the recent trends in HVDC project costs based on publicly available sources to address questions related to cost-effectiveness of deploying HVDC solutions for renewable integration. Third, ICF relied on three detailed case studies—TransWest Express (TWE) Project interconnecting Wyoming and California, Plains & Eastern's Clean Line Project in Southwest Power Pool (SPP) and the Tennessee Valley Authority (TVA) service territory, and Midcontinent Independent System Operator's (MISO's) conceptual HVDC network—to address the questions outlined in the project scope. The key findings from the study are summarized below.

The negative impacts of non-dispatchable renewable generation include generation curtailment, depressed or negative energy prices, system stability issues because of mismatch of generation and demand, increased need for ancillary services, and inefficient unit commitment and dispatch. Increased grid interconnection through HVDC transmission would enable more flexibility in power transmission from regions with excess renewable resources (host) to regions with high electricity demand (client). Since HVDC is decoupled from the alternating current (AC) system, the transfer from the host to client regions can be achieved with minimal impact on the underlying AC transmission system of the host region. Further, because HVDC has relatively low losses over long distances, the distance between the host and client regions does not affect the ability to derive the renewable integration benefits.

Without a detailed modeling of HVDC projects, it is difficult to ascertain if there would be any reliability implications of using an AC network of the host region to interconnect renewable resources in the host region. The renewable penetration levels at which HVDC solutions are likely to be deployed (that is, in lieu of AC solutions) to mitigate non-dispatchable generation impacts tend to vary across bulk power system. Factors such as the robustness of the underlying transmission network, the mix of generation resources, availability of flexible resources, and the nature of the ties to neighboring systems will all affect the level at which HVDC solutions will be deployed. Nevertheless, the current consensus from a review of available literature is that HVDC lines make economic sense at higher penetration levels of renewables.

The cost of an HVDC transmission system depends on many factors such as power capacity to be transmitted, type of transmission medium (submarine or land-based), environmental considerations, access to easements rights-of-way (ROWs), and cost of converter stations and associated equipment. A lack of recent HVDC projects in the United States makes it difficult to ascertain typical project costs. Based on a review of recent proposals and relevant regulatory filings, the cost of HVDC projects ranges between \$1.17 million per mile and \$8.62 million per mile (2017\$).

2. Introduction and Background

EIA is interested in assessing the potential for HVDC transmission networks to mitigate the impacts of non-dispatchable generation technologies. Non-dispatchable technologies (or intermittent or variable generation technologies), like solar and wind, operate when the indigenous resources are available, thereby creating dispatchability challenges for system operators.

Some of the key operational issues associated with variable or intermittent generation include lack of sufficient generation resources during the times of high system demand, excess generation resources during times of low system demand, and increased need for ancillary services (like spinning or non-spinning reserves) to meet the ramping requirements associated with fluctuations in intermittent generation. One application of HVDC lines suggested in the literature is the use of these transmission lines to interconnect different regional power markets. These interconnections help to deliver power from a power surplus region (host region) to that of a power deficient region (client region). The HVDC terminals function as a point-source generation injection to balance variations in intermittent renewables generation in a given regional network.

2.1. Objectives of Report

2.1.1. Review of questions to be answered

The goal of the project is to assess the technical potential challenges in deploying HVDC interconnections to mitigate the impacts of variable generation, and evaluate recent cost trends associated with these types of projects. As outlined in the project scope document, ICF addresses the following questions in this report:

- How and to what extent HVDC transmission may be used to mitigate non-dispatchable generation impacts?
- Are direct current (DC) tie lines between balancing authorities sufficient to transfer system impacts from host to client regions, or must the non-dispatchable generator(s) be directly connected to the client region, bypassing any interaction with the host region?
- Are some system configurations and topologies of AC and DC interfaces more effective at mitigating some or all impacts from non-dispatchable generation?
- At what penetration levels of non-dispatchable generation would we expect these solutions to be deployed?
- How does the penetration level change based on the type of non-dispatchable technology deployed, the share of conventional generation technologies, and/or other regional characteristics?
- What other parameters influence and/or determine the deployment of HVDC?
- Are there limits to how well HVDC can mitigate intermittency impacts?
- What are estimates of the cost of deploying HVDC for these purposes at various levels of supply?

The report addresses the following questions in relation to estimating the cost and rate of return on investment of deploying HVDC:

- What has been the historical cost per mile or cost per MW-mile in developing HVDC transmission facilities in the United States?

- What are the cost components, specifically fixed (costs that are independent of line length) and variable costs (costs that are a function of line length)?
- What factors influence these costs (such as regional labor costs, geography, population density, and so forth)?
- What cost-related factors may constrain HVDC deployment?

2.1.2. Discussion of approach

To address these questions, ICF reviewed several publicly available sources, mainly focusing on renewable energy grid integration and HVDC line costs. Except for a few merchant HVDC projects, there have been few HVDC line projects in recent years in the United States. As a result, a lot of the current available research on this topic originates from Europe, where many HVDC projects are being proposed and are currently being implemented for renewable integration. The sources discussed are mostly peer-reviewed journal articles, research reports, industry newsletters, or case studies published by industry vendors, research labs, and other reputed transmission industry stakeholders. The HVDC cost trends were also extracted from publicly available sources. The National Renewable Energy Laboratory (NREL) JEDI 2017 report contains the most detailed cost breakdown of HVDC transmission including annual operation and management (O&M) costs for hypothetical HVDC projects. ICF also relied on the Transmission Expansion Planning Tool used by the Western Electricity Coordinating Council (WECC) since 2014, which provides capital and other miscellaneous costs relating to HVDC transmission projects. The full list of resources examined is included in the bibliography.

2.1.3. Report structure

The remainder of this section provides a brief historical background on HVDC technology. The third section examines the main issues posed by EIA—examining the impacts of HVDC lines in mitigating the system impacts of variable energy generation from renewables. The report also examines three case studies—the TWE project interconnecting Wyoming and California, Plains & Eastern's Clean Line Project in SPP and TVA, and MISO's conceptual HVDC network—to highlight the challenges and issues related to HVDC and renewable integration. This section includes a summary of insights from the three case studies in a question-and-answer format designed to address the questions raised in the project scope. The study also examines the cost trends for recent HVDC projects to address the cost-related questions in the project scope. The Appendix includes five sections: a summary of recent reports and articles on utilizing HVDC technology to address renewable intermittency issues, detailed discussions of the shortlisted case studies, an inventory of existing and proposed HVDC projects in the United States, and a glossary of technical terms used in the report.

2.2. Overview of HVDC Technology

2.2.1. History of HVDC technology

Power plants are often located near an energy source, such as a coal mine, to minimize fuel transportation costs. These power plants often are located away from heavily populated load-centers; therefore, transporting the electricity generated economically is important. This is accomplished by transmitting the generated power at a high voltage (stepping up at the power plant and stepping down at the substation using a transformer at both ends). Early pioneers like Thomas Edison who first began to harness electricity for useful purposes did this by placing generators right next to the equipment that used the electricity. These early generating stations delivered electricity over copper wires using DC, a method so inefficient that the power plants had to be within a mile of the load they served.

The first commercial power station was installed at Pearl Station in lower Manhattan, New York, in 1882 (DOE 2014). In the late 1880s, George Westinghouse and others developed cost-effective transformers to step up and step down the voltage of AC electricity. With the development of transformers, AC power could be sent over long distances using relatively smaller wires at a higher voltage. However, by the 1890s other inventors like Nikola Tesla further refined and commercialized the AC power distribution system. Cities across the world started constructing high-voltage power transmission lines that used AC technology, thereby firmly establishing the prominence of AC technology for transmission purposes. Typically, transmission of electric power is accomplished at high voltages where the transmission losses are minimized. For a given quantity of power, doubling the voltage will deliver the same amount of power at half the current flow. Doubling the voltage reduces the power losses by a factor of four.[1]

Most of the early attempts to transform the DC voltage to higher or lower levels relied on mechanical devices, which were not cost-effective on a commercial scale. The early research on HVDC technology and potential converter technologies was pioneered by Sweden's ASEA (Long and Nilsson 2007).[2] Dr. Uno Lamm of ASEA first patented low-pressure mercury-arc converters for HVDC applications in 1929. There were other technical and manufacturing issues before the first practical mercury-arc valves could be built. Early demonstrations of HVDC technology was also tested and implemented in the Soviet Union (now Russia) in 1951 between Moscow and the nearby city of Kashira (Long and Nilsson 2007). The first commercial HVDC link, developed by ASEA, was constructed in 1954 for carrying power between mainland Sweden and the island of Gotland. The line was rated at 100 (kilovolt) kV and had the capacity to deliver 20 megawatt (MW) of power.

2.2.2. Modern HVDC lines deployment trends

In the 1970s, HVDC lines were constructed with solid-state converter devices like thyristor valves. HVDC that uses thyristor valves is also known as line-commutated converter (LCC) HVDC (Long and Nilsson 2007). In the mid-1990s, voltage-source converters (VSCs) were commercialized for HVDC applications. In recent years, power electronics devices like insulated-gate bipolar transistors (IGBTs), gate turn-off (GTO) thyristors, and integrated gate-commutated thyristors (IGCTs), have made smaller HVDC systems more economical (Rudervall, Charpentier and Sharma 2000). Currently, the longest HVDC line in the world is the Rio Madeira link in Brazil, which connects hydropower plants in the Madeira River in the Amazon basin to major urban load centers like Sao Paulo and Rio de Janeiro in southeastern part of Brazil (ABB n.d. a). This HVDC link consists of two bipolar 600 kV DC transmission lines with a line length of 2400 kilometers (km) and a transmission capacity of 3150 MW on each pole. China currently leads in the construction of HVDC transmission lines in the world today. China has also successfully implemented ultra-high-voltage direct current (UHVDC) transmission lines in recent years (rated at 800 kV and above) (ABB 2016). China

[1] Power P = V*I. Doubling of voltage (V), reduces the current (I) by half.
Power loss L =I2*r= (P/V)2*r. Doubling of voltage, reduces the losses (L) by a factor of four.

[2] Allmänna Svenska Elektriska Aktiebolaget (ASEA) (General Swedish Electric Company) was a Sweden-based engineering company. In 1988, it merged with the Swiss company Brown, Boveri & Cie (BBC), which then became the ABB (ASEA Brown Boveri) Group. ASEA is now the holding company of ABB Group.

is currently planning to build the Changji-Guquan UHVDC link between Xinjiang regions in the northwest to Anhui province in the eastern region of China. The UHVDC line is expected to be rated at 1100 kV voltage, 3000 km in length, and 12 gigawatt (GW) of transmission capacity. When completed, this project is expected to set world records for HVDC lines in terms of voltage level, transmission capacity, and line length.

2.2.3. HVDC deployment in the United States

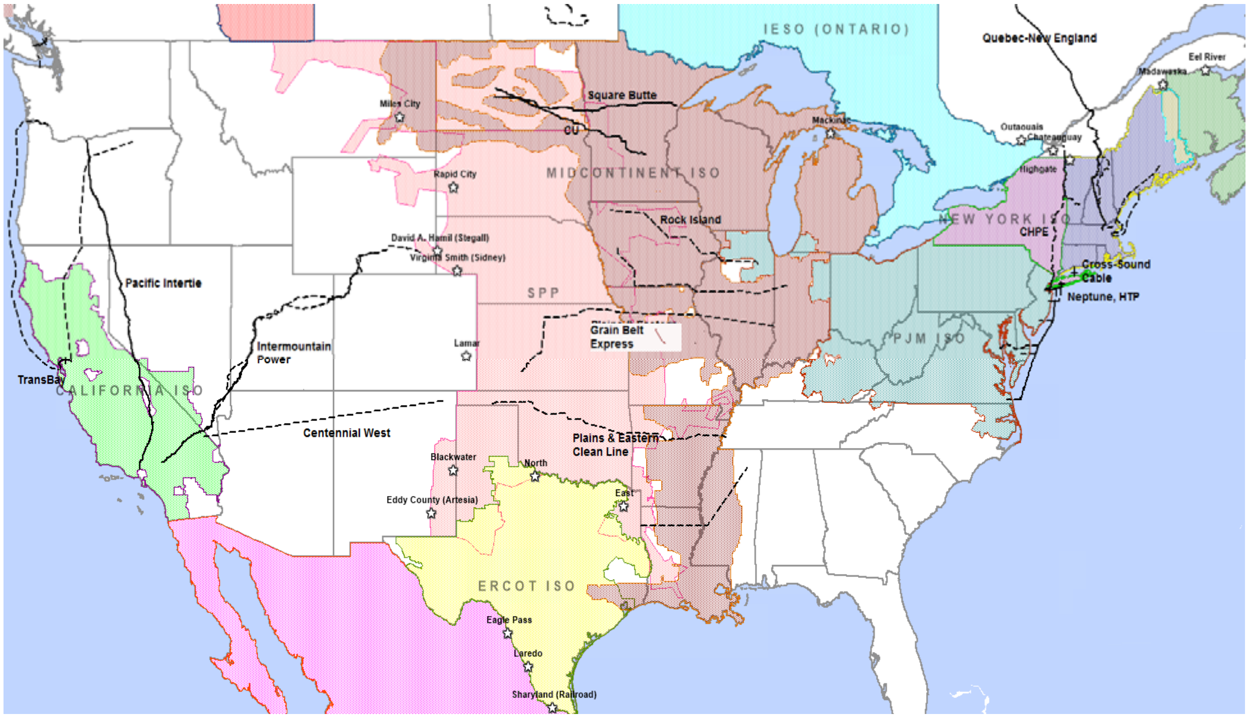
In the United States, the first commercial HVDC project was the 500 kV Pacific DC Intertie connecting Bonneville Power Administration's (BPA) service territory in the Pacific Northwest to Los Angeles Department of Water and Power (LADWP) service territory in California (Bonneville Power Administration 2010). The project was completed in 1970 and was undertaken as a collaborative effort between General Electric of the United States and ASEA of Sweden. The line was built to deliver low-cost hydropower from BPA region to load centers in southern California. The other important HVDC line in the Western Interconnection region is the Intermountain HVDC Transmission link (or Path 27) between Adelanto Converter Station in LADWP service territory in California and Intermountain Converter Station in Delta, Utah. The line is a bipolar line capable of operating at ±500 kV and can transmit up to 2400 MW of power. In the Eastern Interconnection, the longest-operating HVDC link is the Quebec – New England Transmission that connects Radisson, Quebec and Sandy Point in Ayer, Massachusetts (in ISO-NE service territory). The line is capable of operating at ±450 kV and can transmit up to 2000 MW. This line was built to deliver low-cost hydropower from the Hydro Quebec region to load centers in Boston area of Massachusetts.

In addition to these utility-developed HVDC links, numerous merchant HVDC links have also been developed in recent years. These projects are primarily submarine cable systems that interconnect adjacent ISO/RTOs or supply power to large urban demand centers. These include Trans Bay Cable in San Francisco (±200 kV, 400 MW); Cross Sound Cable (± 150 kV, 330 MW); Neptune Cable (550 kV, 660 MW); and Hudson Transmission Partners (660 MW). In addition, there are more than 15 HVDC facilities or AC-DC interties between the grid networks in North America, including the Eastern Interconnect, Western Interconnect, Electricity Reliability Council of Texas (ERCOT), and Comisión Federal de Electricidad (CFE) Mexico.

Currently, there are plans to develop the 600 kV, 4000 MW Plains & Eastern Clean Line to deliver wind power from the Oklahoma-Texas Panhandle to Arkansas, Tennessee, and other states in the region (Clean Line Energy Partners 2017a).The project is being proposed to integrate potential wind resources in the Oklahoma-Texas Panhandle region (commonly referred to as the "wind alley" region of SPP). Other HVDC projects like Champlain Hudson Power Express (between United States-Canada border to New York Metro area), TWE Transmission Project (between southern Wyoming and Las Vegas metro area), and Northern Pass project (between Quebec in Canada and New Hampshire in the United States) are all currently in the planning pipeline.[3] Figure 1 illustrates the existing and proposed lines. Appendix A.4. provides a list of existing and planned HVDC lines in the United States and their characteristics.

[3] For information on the existing HVDC lines and proposed projects see: Cross Sound Cable Project; Trans Bay Cable; Neptune Cable; Hudson Transmission Partners; TransWest; and Northern Pass.

Figure 1. Existing and planned HVDC lines and interties in North America



Source: Created by ICF using ABB Velocity Suite Note: Dashed lines represent planned HVDC projects.

2.2.4. Technical features of HVDC technology

2.2.4.1. HVDC layout

Some of the key technical features of an HVDC transmission line are explained in Figure 2. An HVDC transmission link consists of one or more generator source(s) (except in the case of interties), AC transmission lines (as part of a dedicated collector system or the local AC network), an AC to DC converter station, HVDC transmission lines, a DC to AC converter station, AC transmission and distribution lines, and end-users. The first converter station converts energy from AC to DC power and then the energy is transmitted through HVDC transmission lines. Unlike in conventional AC lines, the power flow on HVDC lines is unidirectional and can be controlled. At the receiver end of the line, the converter station converts energy from DC to AC power. The power is then fed to the existing AC transmission and distribution system for delivery to end-users.

2.2.4.2. Converter technologies

An important component of HVDC technology is the HVDC converter. An HVDC converter transforms electric power from AC to DC and vice versa. A complete converter station for an HVDC may consist of several converters in series or parallel. Most HVDC converters are inherently bi-directional operating as a rectifier (converting AC to DC) or as an inverter (converting DC to AC). Some of the HVDC lines connecting remote generators may be optimized for power flow in one preferred direction (that is, toward load centers).

Early HVDC converters, like the Thury system, rely on electro-mechanical devices. The Thury system relied on several motor-generator sets in series at respective ends of the terminals. The main limitation of the Thury system was that the series distribution meant there was a greater possibility of power failures. In addition, the Thury system had high conversion losses and frequent maintenance issues. In the early

1930s, mercury-arc valves were developed and it took well over two decades for the technology to be incorporated in a commercial HVDC line. Mercury valves rely on line voltage of the AC system to which the converter is connected to force the current to zero and turn off the valve. Therefore, converters built with mercury-arc valves are known as line-commutated converters (LCCs). Mercury-arc converters were used until the early 1970s. In North America, the Nelson River DC Transmission System in Canada was the largest operating HVDC line with mercury-arc valves.

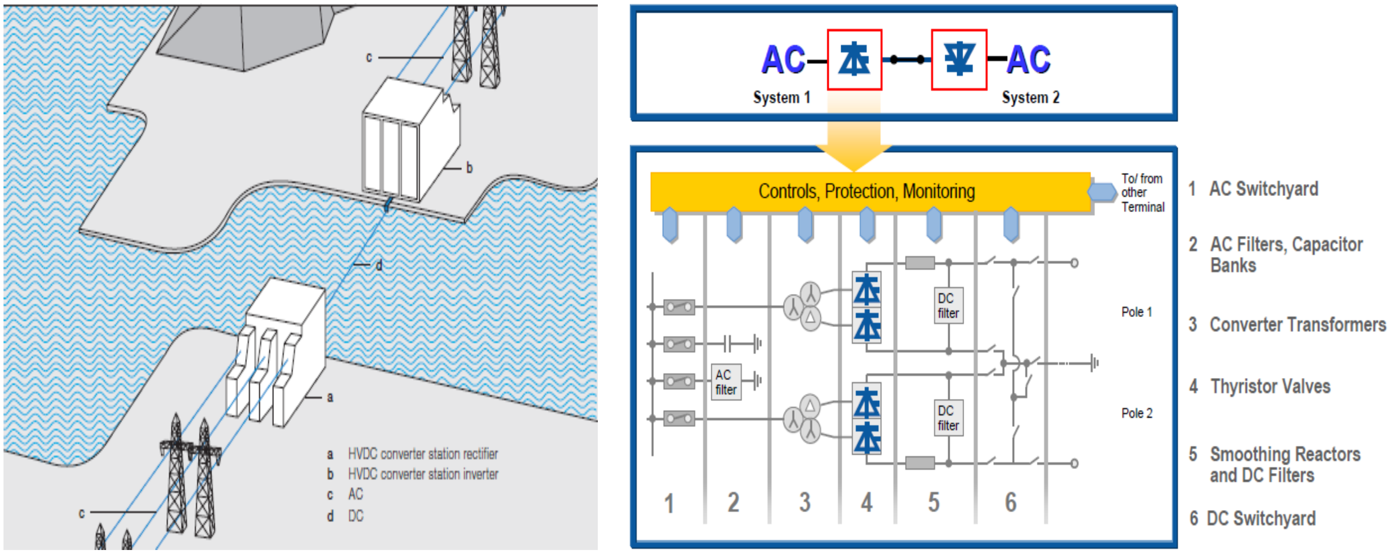
Since the 1970s, many of the HVDC lines with mercury valves were replaced with thyristor or other converter technology. Thyristor valves are solid-state semiconductor devices that require external an AC circuit to turn them off or on. Like mercury-arc valves, even HVDC lines using thyristor are referred to as LCC HVDCs. Thyristor valves have a breakdown voltage of a few kilovolts each. For a commercial HVDC converter station, thyristor converters are constructed using a large number of thyristors connected in series. Additional passive components like grading capacitors and resistors are connected in parallel with each thyristor to ensure the voltage is shared between the thyristors. In a typical converter station, there could be hundreds of thyristor circuits. An incremental improvement to the thyristor-based commutation are capacitor-commutated converters (CCCs). The CCCs use a commutation capacitor inserted in series between the converter transformer and the thyristor valves. Most of the operating HVDCs lines in the world today rely on thyristor-based converter technology for conversion.

Since thyristor-based converters can only be turned on by control action and require external AC line supply to switch them off, they cannot feed power into a passive system. To overcome this shortcoming, VSCs using semiconductor devices were developed (Flourentzou, Agelidis and Demetriades 2009). Such converters have the ability not only to turn on but also to turn off. Two types of semiconductors are typically used in VSCs: GTO thyristors or IGBTs (Rudervall, Charpentier and Sharma 2000). These converters have additional advantages, such as the fact that they can switch on and off many times to improve harmonic performance and they are not dependent on synchronous machines in the AC system for its operation. A VSC-HVDC can also feed power to an AC network containing only passive load. VSC converters are also much more compact and are preferred for applications where converter station space is at a premium (for example, submarine cables near urban centers). The VSC converter consists of two-level or multilevel converters, phase-reactors, and AC filters. Each single valve element is built up with a number of series-connected IGBTs together with associated power electronics devices. The valves, control equipment, and cooling equipment are usually in enclosures (typically the size of a shipping container), which make the installation and transportation easy.

2.2.4.3. Other HVDC components

In addition to converters, other components are part of a typical HVDC converter station (see Figure 2). Transformers at the HVDC converter station adapt the AC voltage level to the high DC voltage level. AC filters and capacitor banks are installed to limit the amount of harmonics to the level required by the network. In an HVDC conversion process, the converter consumes reactive power, which is compensated in part by filter banks and the rest by capacitor banks. In the case of a CCC, the reactive power is compensated by the series capacitor installed in series between the converter valves and the converter transformer. With VSC converters, there is no need to compensate any reactive power consumed by the converter itself. Therefore, the number of filters required for this this type of converters is reduced drastically.

Figure 2. Schematic of an HVDC line



Source: ABB (2014b) (left) and Retzmann (2012) (right).

2.2.4.4. HVDC cables

For HVDC transmission, the transmission lines can be overhead lines or submarine cables. The overhead line is typically bipolar, that is, two conductors with different polarity. If one pole or line fails, half of power capacity could still be delivered. Some of the HVDC projects are also used for submarine/underground transmission. The HVDC cables are typically of two types: solid and oil-filled. (Rudervall, Charpentier and Sharma 2000) The solid cables are more prevalent and economical. In this type, insulating paper impregnated with high viscosity insulating oil is used. No length or depth limitations are applicable for solid-type HVDC cables. Over the years, the oil-impregnated paper-insulated cables (MI-PPL) have been the mainstay of HVDC cables worldwide. The technology was developed in response to demand for higher voltage, larger capacity (large conductors), and longer transmission line length. This technology is not limited by converter technology. However, its limited service experience and unsuitability for land cable applications (because of its higher weight) may limit the use of this technology to just sub-sea/underground projects. The oil-filled type of HVDC cable are completely filled with a low viscosity oil and work under pressure. These cables are typically used for HVDC applications for less than 60 km (Rudervall, Charpentier and Sharma 2000). In recent years, cross-linked polyethylene cables (XLPE) have also been developed for HVDC applications (Murata, Sakamaki and Abe et al. 2013).

2.2.5. Advantages and disadvantages of HVDC transmission technology

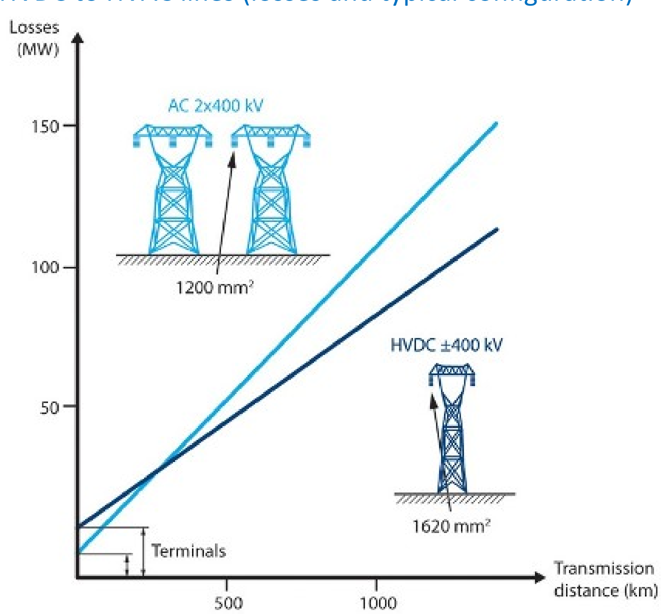
On a point-to-point basis for longer distances, the HVDC transmission scheme is generally cost-effective when compared to an equivalent AC transmission scheme. HVDC lines are also used in niche applications like interties between asynchronous grid networks and submarine cables. The advantages of HVDC applications are summarized below:

- **Superior economics for long-distance application.** HVDC lines are used to evacuate power economically from large power generators located away from demand centers. This could be large hydropower plants (like Madeira Project in Brazil) or a collection of renewable resources in a local area (like the proposed Clean Line HVDC Project for wind resources in the Oklahoma-Texas

Panhandle). HVDC lines are more economical in comparison to equivalent high-voltage alternating current (HVAC) lines because of lower losses and installation costs.

- **Lower reactive and "skin effect" losses:** The power-carrying capability of AC lines is affected by the reactive power component of AC power, and the "skin effect" losses, which cause a non-uniform distribution of current over the cross-sectional area of the conductor. HVDC lines are not affected by reactive power components nor do they experience any losses because of "skin effect."
- **Lower losses:** On average, the losses on the HVDC lines are roughly 3.5% per 1000 km, contrasted with 6.7% for comparable AC lines at similar voltage levels (Siemens 2017). HVDC lines also experience losses at the converter stations, which range between 0.6 and 1% of the power delivered. In a side-by-side comparison, the total HVDC transmission losses are still lower than AC losses for long-distance lines (lower by 30%–40%, typically). Figure 3 compares the losses on a 1200 MW overhead line using HVDC and HVAC configurations. As shown in the figure, beyond the break-even distance of 300 km (or 186 miles), the losses on AC lines are consistently higher than comparable HVDC lines.
- **Smaller right-of-way (ROW) requirements and lower costs:** An HVDC line's transmission tower configuration is also compact and has a smaller ROW requirement than a comparable AC line of similar voltage/capacity. Siemens (2017) reports that there is more than 50% reduction in ROW requirements for UHVDC lines as compared to typical HVAC lines. A bipolar HVDC requires only two cables as compared to a double circuit AC line with six conductor cables (see Figure 3). As a result, the construction costs of HVDC lines are lower when contrasted with comparable HVAC lines.

Figure 3. Comparison of HVDC to HVAC lines (losses and typical configuration)



Source: ABB (n.d. b).

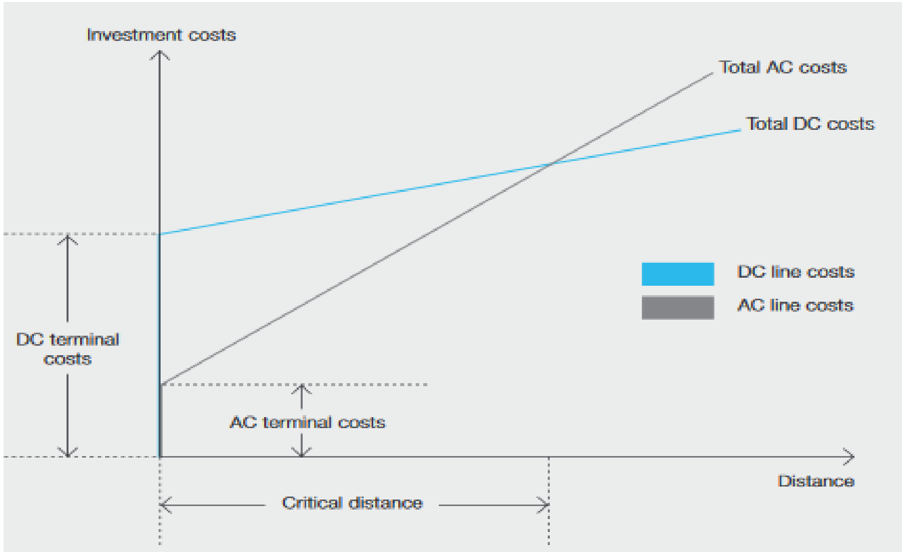
- **Ability to connect asynchronous AC Systems:** HVDC technology is used to interconnect asynchronous AC networks. In the case of any AC lines, the two networks must be synchronized (that is, operated at the same voltage, system frequency, and timing). Since HVDC is asynchronous, it can adapt to any rated voltage and frequency it receives. Hence, HVDC technology is used as interties between asynchronous AC networks worldwide.

- **Suitability for underwater applications:** HVDC technology is the predominant choice for submarine cables. A cable with insulated sheets and metal outer sheath acts like a capacitor. With longer distance cable, the capacitance (of the cable increases. For long-distance AC transmission using cables, the reactive power flow resulting from the large cable capacitance will limit the maximum possible transmission distance. Hence, HVDC lines are the only viable options for long-distance submarine cables. For these reasons, HVDC lines are preferred for interconnecting offshore wind plants worldwide.
- **Higher capacity rating:** HVDC lines are also operated at rated peak voltage conditions at all times, unlike AC lines that on average operate at a root-mean square (RMS) value of the rated peak voltage. Since the RMS voltage ratings is only 71% of the peak, the power transmission capability when operating with HVDC is approximately 40% higher than the capability when operating with AC.
- **Ability to handle longer periods of overload operations:** HVDC lines can operate at overload capacity for a limited period (usually at 10%–15% higher than the rated capacity for less than 30 minutes). This would give sufficient time for system operators to implement mitigation measures under contingency conditions. Such extended operation of the line under overload conditions is not possible with AC lines.
- **Ability to manage instabilities:** Since HVDC lines can operate asynchronously, they are used to ensure system stability by preventing cascading failures from propagating from one part of the grid to another. The direction and magnitude of power flow on DC lines can also be controlled by system operators. These lines could be used for power injections to balance the grid during any supply-demand imbalance.

The HVDC transmission scheme also has disadvantages that relate to cost, conversion equipment, switching, control, and availability. The disadvantages of HVDC transmission schemes are summarized below:

- **Higher costs at short distances.** As explained earlier, HVDC lines are cost-effective only beyond a certain break-even distance for corresponding voltage and power capacity. The cost of HVDC projects are also higher due to converter stations and associated equipment. HVDC projects make economic sense only for projects exceeding a certain critical distance. As a rough rule of thumb, ABB reports this critical distance as 60 km (or 37 miles) for HVDC submarine lines and 200 km (or 124 miles) for overhead lines (ABB 2014b). For shorter distances, the investment in HVDC converter stations and related assets may be larger than comparable AC transmission lines. Also, maintaining an inventory of customized HVDC assets imposes additional costs on the system operator/transmission line owner.

Figure 4. Cost comparison curves for HVDC and AC lines (generic estimates)



Source: ABB (2014b).

- **Limited control between terminals:** In contrast to AC transmission systems, implementing a multi-terminal HVDC system is complicated and cost prohibitive. Controlling power flow between terminals remains a technical challenge.
- **Lower availability:** HVDC schemes offer lower availability than comparable AC systems, mainly due to conversion stations and associated equipment. In addition, the converter stations have limited overload capacity.
- **Greater complexity in components.** HVDC circuit breakers are difficult to build since some kind of mechanism needs to be developed to force the current to zero without causing arcing and contact wear. Mechanical circuit breakers are too slow for HVDC lines, although they have been predominantly used in other applications. Only recently have commercial circuit breakers for HVDC applications been introduced in the market (ABB 2012), which uses a combination of power electronics and fast mechanical breakers.

3. Analysis and Results

3.1. Role of HVDC in Mitigating Non-Dispatchable Generation Impacts

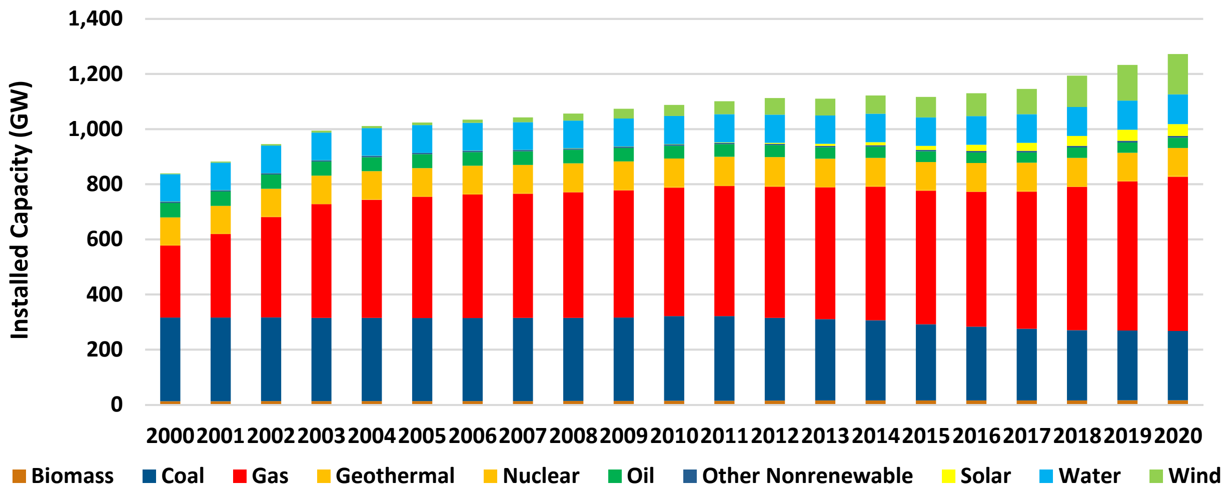
3.1.1. Impact of large-scale non-dispatchable generation on system operation

The U.S. generation portfolio is undergoing a significant transformation with ongoing retirements of baseload units like coal and nuclear, and growth in natural gas, wind, and solar resources (APS Physics 2010, NERC 2016). This shift is driven by several factors, such as existing and proposed federal, state, and regional environmental regulations, low natural gas prices, and the integration of both distributed and utility-scale renewable resources. Renewable resources can be categorized as either (1) dispatchable renewables (for example, hydro, geothermal, and biomass), which can be dispatched based on system requirements, or (2) non-dispatchable renewables (for example, solar and wind), whose output depends on weather conditions and time of day, and cannot be operated in response to dispatch signals. The increasing deployment and penetration of non-dispatchable renewable resources like solar and wind across the country could pose special challenges to the system operators since these resources cannot be controlled to meet grid requirements.

Two features of non-dispatchable renewable resources may prove problematic for overall grid operation and reliability. First, the output from renewable resources like solar and wind are variable over time and are subject to local weather conditions. Unlike other conventional technologies like fossil fuel, hydro (including pumped storage), and nuclear, the output from renewables cannot be planned and dispatched in advance to meet the projected demand. As a result, these resources are sometimes termed as variable energy resources (VERs). At low renewable penetration level, VERs pose no system reliability issues. However, at higher penetration levels, the system demand minus VER generation (or net load that must be supplied by other dispatchable resources) varies significantly and becomes difficult to predict. This poses system reliability and power dispatch/commitment challenges to grid operators. The second factor is the variability in renewable generation calls for increased ancillary service resources to meet higher ramping requirements, frequency, and voltage support. Some of the reliability services affected by large integration of VERs include ramping requirements, system inertia and frequency response, and active and reactive power controls. As penetration of VERs increases, the need for additional system flexibility and ancillary service requirements will also increase.

In the United States, the share of VERs in the overall capacity mix has been steadily increasing in recent years. The total installed capacity of solar and wind resources in the country are currently estimated to be around 106 GW (out of a total capacity of 1,130 GW as of end of 2016). This share is expected to increase in the near future as the share of VERs increase to 190 GW by 2020 (out of a total expected capacity of 1,272 GW by 2020). By 2020, the VERs are expected to constitute nearly 15% of the installed capacity in the United States. The share of VERs is higher in some of the ISO/RTOs like California Independent System Operator (CAISO), ERCOT, and SPP. Two important factors are driving the surge in deployment of VERs. First, federal incentives like investment/production tax credits are driving the renewable growth in recent years (DSIRE 2017). With the incentives expiring in the near future, there is a rush to develop wind and solar resources. Second, the renewable portfolio standards (RPSs) or obligations set by different states are contributing to the renewable build-up. To date, nearly 29 states and Washington, DC, have implemented some form of a mandatory RPS policy (DSIRE 2017). Additionally, eight additional states have RPS obligations that are not binding. States like California and New York have set ambitious RPS targets of 50% or more by 2030. With these changes, the national generation portfolio in the near- to long-term future is expected to change significantly.

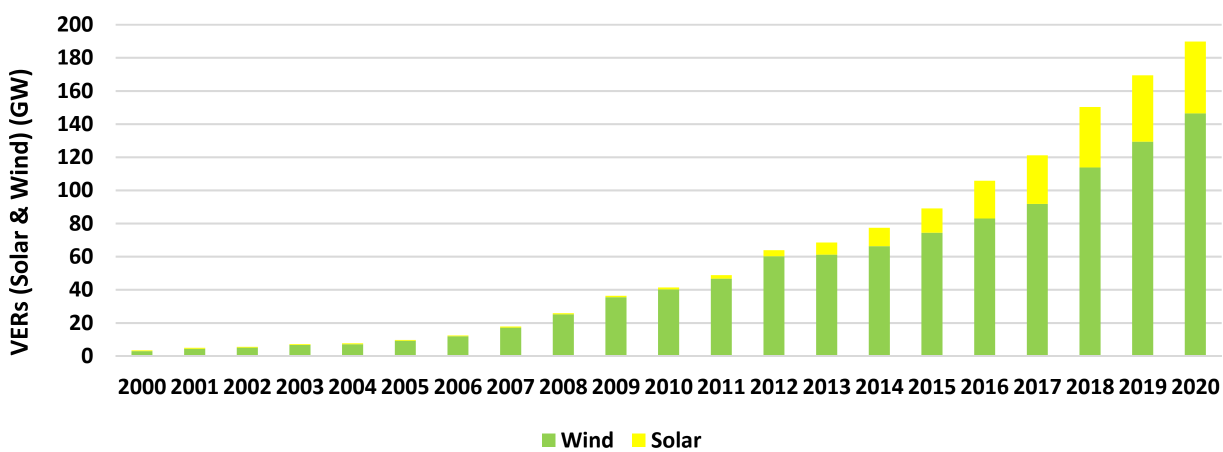
Figure 5. Generation capacity in the United States by fuel type (existing and planned)



Source: Compiled by ICF using SNL data.

Note: Future capacity estimates are based on actual planned and under-construction projects.

Figure 6. Wind and solar generation capacity in the United States (existing and planned)

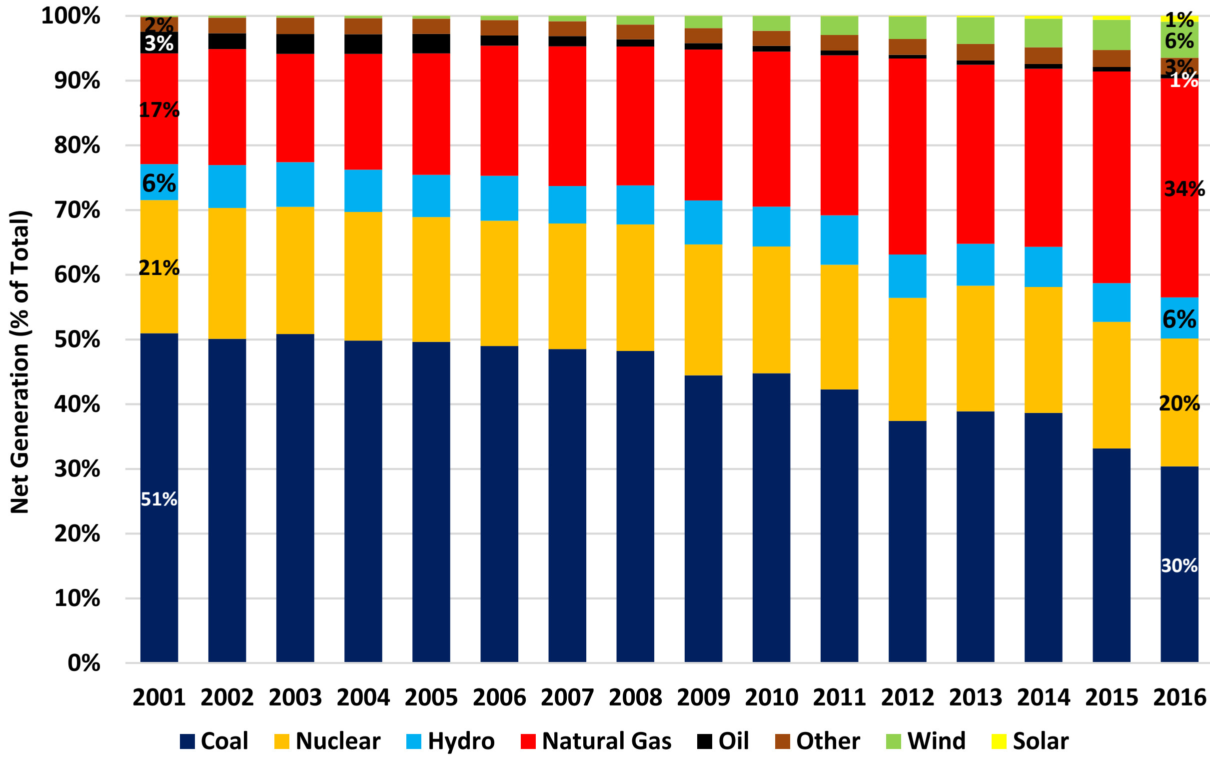


Source: Compiled by ICF using SNL data.

Note: Future capacity estimates are based on actual planned and under-construction projects.

The net generation trends for the United States also show an increasing dispatch from VERs like solar and wind. In 2016, wind and solar contributed nearly 7% of the total generation. From 2001 to 2016, the net energy generation from VERs increased from 7,280 GWh to nearly 263,626 GWh, with an average annual growth rate of 27% for the past 15 years. This trend is only expected to increase in the near future with the planned capacity of solar and wind projects in the pipeline. In the future, curtailment of output from VERs is also likely to emerge as an acute issue because of over-generation concerns during light-load conditions or potential overloading of transmission lines because of transmission constraints. As penetration of VERs increases on the grid, additional system flexibility and essential reliability service requirements will also increase.

Figure 7. Net generation trends in the United States (by fuel type)



Source: Compiled by ICF using EIA data.[4]

3.1.2. Potential HVDC solutions application

A transition to a higher share of VERs in the future requires modifications to the country's existing electric grid (IEA-ETSAP, IRENA 2015, APS Physics 2010). Although the focus of this report is on HVDC technology, a brief overview of other technological options for renewable integration is provided in this section for reference. From a technical perspective, increasing VER penetration calls for smart grid technologies, widespread energy storage, HVDCs line deployment, and adding more flexible generation technologies. From a market perspective, the regulatory framework must also adapt to reflect the cost structures of integrating VERs and allow for new services and revenue streams to support these technological options.

As more non-dispatchable renewable resources are deployed, the economic dispatch of conventional thermal generation will be significantly affected, requiring generators to ramp up and cycle more often to account for increased variability. Flexible generation resources like fast-ramping gas turbines and certain storage facilities can offer the necessary grid flexibility. Flexible generation resources refer to resources that interconnect directly to the bulk transmission system and generally possess "fast-ramp" capabilities. Such resources are crucial to balance the overall supply-demand fluctuations caused by VERs. Smart gird technologies can also act as an enabler for greater VER integration. Some of the load or demand-side

[4] See EIA Electricity Data Browser.

technologies like demand-side management and advanced metering infrastructure help the system operator to maintain supply-demand balance in light of intermittent output from VERs. Smart grid technologies like phasor measurement units (PMUs) and advanced control systems help system operators to maintain grid reliability in light of intermittent output from VERs. New advances in wind and solar technologies allow them to operate over a wide range of conditions and provide ancillary services like frequency and voltage control. This could also contribute to bulk system reliability. Energy storage technologies can alleviate short-term variability caused by the intermittent nature of VER output. Energy storage can also alleviate long-term variability through careful scheduling and operation of pumped-storage hydropower units. In addition, distribution-level grid configurations like micro-grids and island systems can also facilitate greater integration of VERs in the future.

Increased grid interconnection at regional, national, and trans-national grid networks would enable more flexibility in power transmission from regions with excess renewable resources to regions with high electricity demand. Higher interconnection and transmission capacity also enables the optimal use of surplus generation, alleviates the problems associated with intermittent generation from VERs, reduces the requirements for ancillary services, alleviates congestion, and obviates the need for new generator resources in some cases.

However, the focus of this report is restricted to application of HVDC technology to mitigate the problems associated with renewable intermittency. Not only do HVDC lines facilitate integration of new VERs, they can also mitigate the impacts of such resources on grid reliability. Many of the promising wind and solar resources are located far away from the major load centers in the contiguous United States. Integrating these resources would require constructing new HVDC lines connecting these regions to major load centers across the country. Conventional HVDC technology can facilitate the integration of renewable resources like wind and solar spread out in a given local area. HVDC technology also offers a partial solution to the problem of intermittency of renewable energy. Aggregating the output of VERs over many individual units substantially increases bulk system reliability and decreases overall supply fluctuations as well. HVDC lines can also help to transfer power from generation-excess regions to generation-deficient regions to balance the system. Because of these advantages, system operators and developers favor HVDC solutions to integrate and deliver power to load centers. As discussed earlier, several HVDC transmission projects are currently proposed to integrate wind resources in the upper-central Midwest areas, and solar resources in southwestern areas of the United States to the demand centers on the East and West coasts. The suitability of such transmission solutions and challenges in implementing the solutions are explained using three specific case study examples discussed in Appendix A.1.

3.2. Summary and Insights on Costs from HVDC Project Case Studies

This section summarizes key insights and answers to the key questions formulated in the project's scope, which are based on the literature review conducted for this report and the detailed case studies discussed in Appendix A-1.

How and to what extent may HVDC transmission be used to mitigate non-dispatchable generation impacts?

The negative impacts of non-dispatchable generation include generation curtailment, depressed or negative energy prices, system stability issues because of mismatch of generation and demand, increased need for ancillary services, and inefficient unit commitment and dispatch. Increased grid interconnection through HVDC transmission would enable more flexibility in power transmission from regions with excess renewable resources to regions with high electricity demand. As discussed, HVDC has characteristics that allow it to mitigate the non-dispatchable impacts and improve renewable resource integration. These characteristics include DC power flows being controllable, low losses over long-distance transmission, and the ability for asynchronous interconnection (allowing for efficient ties between different balancing authorities and even different interconnections).

The studies reviewed in this report demonstrate the capability of HVDC to mitigate some of the impacts of non-dispatchable resources. HVDC can deliver excess generation from the host region to a client region that has a demand for the output of the renewable resource. Because HVDC is decoupled from the AC system, the transfer from the host to client regions can be achieved with minimal impact on the underlying AC transmission system of the host region and any neighboring regions. It also allows for the interconnection of host and client regions that could be in different interconnections, which would not be practical for AC lines. In cases where the host and client regions are not in the same balancing authority, HVDC can reduce operational issues that might arise from loop flows.[5] Further, because HVDC has relatively low losses over long distances, the distance between the host and client regions does not affect the ability to derive the renewable integration benefits. For example, TWE will interconnect locations that are 725 miles apart, while the Plains & Eastern Clean Line will transport wind energy over 700 miles.

Evacuating excess energy from the host region helps reduce curtailments and depressed or negative prices, improve system stability, and reduce the need for ancillary services. Generation that would otherwise be curtailed can be used in areas with a demand for renewable generation. This is demonstrated in Brenna et al. (2017), where the introduction of an HVDC interconnection between northern and southern Italy reduced curtailment of wind generation by approximately 79% and improved overall benefits to customers. The MacDonald et al. report (2016) also showed that HVDC interconnections between regions could facilitate the delivery of renewable generation from areas with a surplus to demand regions, and reduce curtailments in the system as a whole. The ability to deliver excess generation to the demand regions helps sustain power prices and reduce the number of incidences of negative prices. A similar conclusion can be drawn from NREL's Bloom, Townsend et al. (2016) study, which examines various renewable penetration levels combined with different transmission topologies. HVDC transmission expansion, which allowed more export to other regions improved renewable

[5] Electricity tends to flow along the path of least resistance. Loop flows are electricity flows through the electric grid to avoid congested lines/paths.

integration and reduced curtailment. Simulations in the TradeWinds (2009) study show that HVDC transmission upgrades can improve renewable integration and reduce overall operating cost.

The APS Physics (2010) study does not provide any simulations that demonstrate the benefits of HVDC, but it discusses the ability of HVDC to mitigate the intermittency and variability impacts of renewable generation. High-capacity, controllable, long-distance transmission lines can allow excess generation in one area to be directed to specific targets of deficit far away, instead of being sidetracked in the grid by local conditions.

The TWE project also demonstrates the extent to which HVDC can mitigate non-dispatchable generation impacts. Without the TWE project, it will not be feasible to develop and interconnect 1,500 to 3,000 MW of wind generation to the weak Wyoming transmission grid. Without significant transmission system upgrades, only a small fraction of the wind generation will likely be able to operate. In addition, the reliability of the grid will be compromised. Plains & Eastern Clean Line will also allow for the development of large amounts of wind in Oklahoma that would otherwise create reliability and other problems in SPP. Unlike TWE, which would deliver wind connected to the host region, Clean Line will connect wind directly to the client region, bypassing the host region. Some HVDC lines are also used to resolve intermittency issues in both the host and the client regions depending on the need. One example is the Skagerrak HVDC lines between Norway and Denmark. Recently, ABB commissioned the fourth HVDC line of the project with the objective of balancing loads between Norway's hydroelectric-based system and Denmark's wind- and thermal-based generation (ABB 2015).

The reports and case studies did not explicitly address the extent to which HVDC can mitigate system stability issues that could occur with the integration of large amounts of non-dispatchable generation. TWE indicates that HVDC can provide some mitigation. The 2008 and 2010 TransWest reports show that with the implementation of TWE, the Wyoming grid can accommodate the interconnection of 1,500 to 3,000 MW of wind, which would otherwise not be feasible on the relatively weak Wyoming grid. The report highlights the need for protection schemes that would be necessary to avoid widespread outages under certain contingency conditions involving injection of such a huge amount of power. Additional studies will be required to develop a better assessment of the ability of HVDC to mitigate stability issues.

Are DC tie lines between balancing authorities sufficient to transfer system impacts from host to client regions, or must the non-dispatchable generator(s) be directly connected to the client region, bypassing any interaction with the host region?

Based on the information reviewed in this study, the benefits of HVDC in mitigating the impacts of non-dispatchable generation can be achieved by connecting the host and client regions using an HVDC line, but the non-dispatchable generation does not have to be connected directly to the client region to achieve all the benefits. However, depending on system conditions and the robustness of the underlying AC network it might be necessary to develop protection schemes to maintain reliability in the host region under certain emergency conditions, for example, following the loss of the wind generation or the loss of the HVDC transmission line. In the Brenna et al. (2017) and MacDonald et al. (2016) studies, the benefits of the HVDC line were achieved even though the wind generation was not connected directly to the client region. In both cases, the wind generation was modeled as connected to the AC system in the host region(s), and the HVDC line(s) connected the host and client region(s). Without the HVDC line, the non-dispatchable generation would have a negative impact on grid stability in the host region. The TradeWinds (2009) and the NREL's Bloom, Townsend et al. (2016) studies also provide similar insights.

The preliminary planning report on the TWE project indicates that TWE would connect the host and client balancing authorities, and will not involve the direct connection of wind generation to the client region (TransWest Express LLC 2010). As indicated in the report, the sudden and simultaneous loss of both HVDC circuits of TWE could result in instability and blackouts because of the relatively weak Wyoming grid. This indicates that the wind generation will be connected to the AC system in the host region, Wyoming, rather than directly to the client region via the HVDC line. Therefore, this also shows that the wind generation does not have to be connected directly to the client region to achieve the expected benefits. TWE also demonstrates the potential need for protection schemes in the host region to resolve reliability problems under certain emergency conditions. The preliminary planning report shows that the system can withstand the loss of only one of the two HVDC circuits without becoming unstable. Protection schemes would be required to mitigate the impact of the simultaneous loss of the two circuits.

Similarly, the MISO conceptual study and the Square Butte HVDC project both show that HVDC benefits can be achieved even when the non-dispatchable generation is connected to the host region and not directly to the client region.

Are some system configurations and topologies of HVDC lines more effective at mitigating some or all impacts from non-dispatchable generation?

Based on the limited review of case studies, bi-directional/bi-pole configuration of HVDC lines are always preferable even if the power is expected to flow predominantly from the renewable resources (host region) to the load centers (client region). In addition, VSC-type converter stations would be best suited for providing ancillary services in the form of fast-acting frequency response, thereby making it more effective at mitigating the impacts of non-dispatchable generation. HVDC lines with VSC-type converters can respond to frequency disturbances within a fraction of a second, as compared to a few seconds using primary/secondary control devices like governors or automatic generation control. Further, VSC-type converters can support voltage that helps the AC system to recover faster. HVDC lines can also operate at overload conditions for a longer period (at 10%–15% higher than the rated capacity for less than 30 minutes). This would give sufficient time for system operators to implement mitigation measures under contingency conditions involving variations in intermittent VER output.

The Friends of the Supergrid report (2012) describes hybrid AC/DC systems and states that an HVDC system in parallel to an AC system increases power transmission capacity and at the same time contributes to system stability. Using a simulated fault on an AC line running in parallel with an HVDC line, it demonstrates how the HVDC link can dampen the oscillations resulting from the fault and restore system stability. HVDC improves stability in extended AC systems, which is important for renewable resources that have to be delivered across long distances. ABB's HVDC review (ABB 2014a) emphasizes the ability of HVDC lines to improve stability in hybrid AC/DC systems, and cites the Pacific DC Intertie in the western United States as an example. The area of the country is characterized by long-distance transmission lines that connect generation in the north to load centers in the south. In addition, the report describes other advantages of HVDC in hybrid AC/DC systems, such as the ability of HVDC to act as a firewall and prevent disturbances from spreading from one AC system to another, and to provide artificial inertia.

At what penetration levels of non-dispatchable generation would we expect HVDC solutions to be deployed?

The penetration levels at which HVDC solutions are likely to be deployed to mitigate non-dispatchable generation impacts vary by system. Factors such as the robustness of the underlying transmission network, the mix of generation resources, availability of flexible resources, and the nature of the ties to neighboring systems will all affect the level at which HVDC solutions will be deployed. Additionally, analysis that is more detailed will be required to assess how these factors affect the penetration level, and to determine more specific penetration levels at which HVDC will be deployed.

ICF examined information from selected ISO/RTO regions to determine the penetration levels at which the operators started implementing solutions to address renewable integration issues. Because of the limited information available, this approach is based on anecdotal evidence and it provides indicative measures of the penetration levels rather than precise values. ICF assumed that unless other solutions are preferred, HVDC solutions will be deployed when operators start observing problems on their systems. The annual average penetration levels for CAISO, ERCOT, and MISO are shown in Table 1. The penetration levels range from a low of 4.8% in MISO to 11.5% in CAISO.

Table 1. Penetration levels corresponding to historic market initiatives

Region	Market Initiative	Implementation Year	Annual Average Penetration Level
CAISO	EIM	2014	11.5 %
ERCOT	CREZ	2014	5 %
MISO	DIR, MVP	2011	4.8 %

Source: SNL.

System operators are continuing to operate the bulk power system under high renewable penetration levels. ERCOT, CAISO, and SPP have seen hours wherein the highest hourly penetration has exceeded 50% of the hourly system demand in 2017 (see Table 2). However, all of these regions have implemented large investments in transmission and other mitigating measures to improve renewable integration and penetration levels.

Table 2. Maximum renewable penetration in select ISO/RTOs

ISO/RTOs	Highest Hourly Penetration	Annual Average Penetration
SPP	**54%**	**14.6%**
CAISO	**~54%**	**16.3%**
MISO	**-**	**9%**
ERCOT	**50%**	**11%**

Source: Press articles and SNL.

Note: Renewable penetration is the percentage of system demand met by wind and solar generation in a given period.

The ability to deploy alternative solutions will affect the threshold penetration level for HVDC deployment. CAISO expanded the Energy Imbalance Market (EIM), introduced a flexible resource adequacy product, and lowered minimum threshold for energy bid prices from renewable generators. ERCOT implemented the Competitive

Renewable Energy Zone (CREZ) transmission projects, and MISO implemented a DIR program and developed AC transmission to support renewable integration. The improved penetration levels are shown in Table 3 below.

Table 3. Changes in penetration levels for alternative mitigation solutions

Region	Market Initiative	Implementation Year	Annual Renewables Penetration Level (%)	
			Pre-Change	Post-Change (2016)
CAISO	EIM	2014	11.5 %	16 %
ERCOT	CREZ	2014	5 %	11 %
MISO	DIR, MVP	2011	4.8 %	9 %

Source: SNL.

How does the penetration levels of non-dispatchable generation at which we would expect HVDC solutions to be deployed change based on the type of non-dispatchable technology deployed, the share of conventional generation technologies, and/or other regional characteristics?

Intra- and interregional HVDC lines make economic sense at high penetration levels of VERs deployed. Most HVDC projects in the United States are being proposed to deliver the output from a cluster of wind projects in a local area (for example, TWE and Clean Line HVDC projects). In addition, several existing HVDC lines are designed to transport hydropower generation (for example, Pacific Intertie and Quebec – New England lines). In our experience, for the case of big solar projects, AC lines are typically proposed (for example, Nevada West Connect and SunZia Southwest Transmission projects). Although the type of non-dispatchable technology should not affect the technical feasibility of HVDC lines, these lines have been deployed primarily for wind and hydropower generation to date.

The information examined within the scope of this study is not sufficient to provide a quantitative measure of the effect of the variations in the factors discussed in the answers above. As described qualitatively in the previous question, several factors can affect the penetration levels at which solutions will be required. The type of non-dispatchable technology can have a material impact. Distributed resources, such as solar, present challenges that are different from utility-scale renewable resources. System operators can manage utility-scale renewables to some extent, and even direct that the generation be curtailed to resolve severe reliability problems. Achieving the same level of control with distributed resources is difficult because it is behind the meter and cannot easily be curtailed. We believe some of the recent improvements in several regions to enhance the integration of renewable resources are instructive in understanding how factors such as the nature of the underlying transmission network, the share of conventional generation technologies, and other regional characteristics can affect the threshold penetration level.

In ERCOT, the development of the CREZ lines reinforced the underlying transmission network and allowed the annual penetration level to increase to 11% in 2016 and the maximum hourly penetration reaching a high of ~50% in 2017. This shows that a region with a robust transmission interconnection between host and client areas would have a relatively higher threshold penetration level. A region with an underlying transmission network like the pre-CREZ ERCOT system will need solutions sooner than one like the post-CREZ system. A similar conclusion can be drawn from the impact of the MISO's Multi Value Project

Portfolio (MVP), which has helped improve penetration levels in the region.[6] CAISO's expansion of the EIM shows how market mechanisms and access to neighboring regions can affect the threshold penetration level. CAISO is able to share its surplus generation with neighboring regions, increasing the penetration level at which CAISO would otherwise need other solutions. Table 3, above, shows how changes in regional characteristics can affect the threshold penetration level. As indicated in Table 3, the threshold penetration level was much lower in MISO's case, as compared to CAISO's case, when an alternative mitigation solution was implemented to address renewable intermittency issues.

The feasibility of HVDC solutions is also contingent on technical aspects like the distance between the host and client region, availability of renewable resources in a concentrated local area, whether delivery is point-to-point or special offtake arrangements are required, whether client and host regions are located in the same region or interconnection. Typically, transmission lines within a balancing area rely on AC lines to transfer power (for example, ERCOT's CREZ transmission projects), while transmission line between balancing areas/interconnection rely on HVDC lines (for example, Clean Line and TWE). The characterization of penetration level will also depend on the definition of the area under consideration. Penetration might be low in a region as a whole, but concentrations of non-dispatchable generation within specific sub-regions could result in levels that require mitigation in the sub-region. For example, MISO has a relatively low penetration of non-dispatchable generation region-wide, but mitigation measures have been required in the Minnesota and Iowa areas.

What other parameters influence and/or determine the deployment of HVDC?

HVDC lines are deployed for select applications—delivering large amount of power over a long distance, as an intertie between asynchronous interconnections, and for power transmission using submarine cables. As discussed earlier, HVDC lines are suitable for projects beyond a critical distance for corresponding voltage and power capacity. As a rough rule of thumb, ABB reports this critical distance as 60 km (or 37 miles) for HVDC submarine lines and 200 km (or 124 miles) for overhead lines (ABB 2014b). For shorter distances, the investment in HVDC converter stations and related assets may be larger than comparable AC transmission lines. HVDC lines used in renewable integration requires the availability of large generation potential at or near the HVDC terminals (like wind resources in southern Wyoming for TWE or wind projects in the Oklahoma-Texas Panhandle region for Clean Line Project). HVDC technology is the predominant technology used for submarine cables. For long-distance AC transmission using cables, the reactive power flow due to the large cable capacitance will limit the maximum possible transmission distance. Hence, HVDC lines are the only viable options for long-distance submarine cables.

Are there limits to how well HVDC can mitigate intermittency impacts?

The reports and case studies reviewed in this study did not specifically identify any limits to the ability of HVDC to mitigate intermittency impacts. Limitations might be related to the design of the system rather than the nature of the technology. If the line is appropriately sized to deliver flexible generation to the host region, or to transfer excess renewable generation from the host to the client, then any negative impacts of the non-dispatchable generation will be sufficiently mitigated. Under-sizing the line will limit the line's effectiveness. It will not be able to import sufficient flexible generation to support ramping, load following, or other required support to a host region with significant amounts of non-dispatchable

[6] See MISO MVP.

generation. Alternatively, it will not be sufficient to export excess non-dispatchable generation from the host to client regions and mitigate the impact in the host region.

Oversizing the line can also introduce operational issues and limit its effectiveness. If the capacity of the HVDC line exceeds the threshold at which a potential outage would result in stability problems, it will affect system operations. As discussed in Section 3, TWE would have to be designed to minimize the simultaneous outage of the two 1,500 MW circuits that comprise the project. This precludes the use of a single 3,000 MW HVDC circuit. System planners can develop operating procedures to manage the impact of the loss of the line, but these arrangements will be incremental to the actual project. More detailed studies and analyses would be required to determine specific limitations to the ability of HVDC to mitigate intermittency impacts.

3.3. Cost Trends in HVDC Lines/Technologies in the United States

ICF has reviewed multiple, publicly available sources related to cost trends in HVDC lines. These are sources focused on individual HVDC projects around North America, providing total project cost estimates rather than a detailed cost breakdown. A final cost-per-mile ($/mile) estimate was derived from the total project cost and the cable length of each project. The WECC Transmission Expansion Planning Tool provides a more detailed cost analysis, including substation and converter costs for a 500-kV HVDC bi-pole line.

3.3.1. Cost Estimates from specific case studies of HVDC projects (publicly available)

While specific cost estimates are usually not provided in publicly available sources, NREL's Jobs and Economic Development Impact (JEDI) model contains a detailed breakdown of HVDC project costs, adjustable according to the project location, cable type, voltage, and length. Table 4 contains the cost estimates provided in the JEDI model assuming a 100-mile, 500-kV HVDC bi-pole line, built on flat terrain in a rural area.

The project capital cost is determined as the sum of the transmission line, infrastructure, and services/other costs. NREL also includes costs incurred during the planning and preconstruction phases of the project, along with labor costs that are adjusting according to the state selected for the project (user input). The labor costs included in Table 4 are based on the national U. S. average, as determined by NREL. Using the assumptions mentioned above, NREL suggests that the cost of the new transmission line would be approximately $1.441 million per mile. Labor and installation would cost $637,000 per mile, which is similar to the cost of materials and equipment used ($663,000 per mile). Development and preconstruction costs are projected to be approximately $141,200.

The converter station accounts for the majority of infrastructure costs, at $275 million per station. It is assumed that at least two stations will be required, one for each endpoint of the transmission line. Including labor, and other equipment that may be required (transformer, shunt reactor, etc.), the total infrastructure cost is approximately $367 million per station. An additional $78,000 per mile is added to account for any management services used during project development (site management, legal, public relations, engineering, etc.) This leads to a total project capital cost of $9.17 million per mile.

Along with the project capital cost, NREL provides estimates for the annual O&M costs, which include maintenance labor and materials, any potential ROW royalty payments, insurance, replacement parts, and a sales tax that is dependent on the state in which this project is located. NREL estimates that the annual O&M costs (excluding sales tax) for this project would amount to $13,300 per mile. As discussed in the previous section, distance is an important cost factor, but not a limiting one. NREL[7] also takes into account the terrain class and population density of the site. For example, a 100-mile line going through a town on mountainous terrain would cost 13%[8] more than a line going through a rural flatland. Cost-influencing factors vary between sources. Along with terrain and length, the WECC Transmission Expansion Planning Tool takes into account additional factors, including the conductor[9] and structure[10] types, and the age of the transmission line.[11]

[7] NREL JEDI terrain and population density multipliers: Terrain types include desert, farmland, flat, mountainous, and rolling. Population density types include in-town, near-town, and rural.
[8] This was calculated using the NREL JEDI tool, and comparing layout #1 (mountainous, in-town) with layout #2 (flat /w access, rural).
[9] The three most prevalent conductor types are aluminum conductor steel reinforced cable (ACSR), aluminum conductor steel supported cable (ACSS), and high tensile low sag (HTLS).
[10] Structure could be a lattice tower or tubular steel.
[11] This could be a brand new line or a current line going through re-conductoring.

Table 4. NREL JEDI project cost data for a hypothetical 500 kV, 100-mile bi-pole HVDC line

Project Cost Data Line Item	Unit of Measurement	Cost per Unit ($000)	Total Cost (100 Mile Line, $000)
Transmission Line Costs			
Development and Preconstruction Activites			
Land Acquisition Services	Cost per Mile	19.5	1,950
Private Land Acquisition Payment	Cost per Mile	24.2	2,424
Engineering/Surveying/Geotechnical Consulting Services	Cost per Mile	65.0	6,500
Environmental & Permitting Services	Cost per Mile	32.5	3,250
Subtotal Development and Preconstruction	Cost per Mile	141.2	14,124
Construction Activities			
Materials & Equipment			
Concrete, gravel, asphalt	Cost per Mile	39.0	3,900
Steel structures and poles	Cost per Mile	260.0	26,000
Overhead wires (conductor and insulators and shield wire)	Cost per Mile	364.0	36,400
Subtotal Materials & Equipment	Cost per Mile	663.0	66,300
Labor/Installation			
Civil (grading, roads, site prep, foundations, fencing)	Cost per Mile	312.0	31,200
Heavy Construction (Tower erection, Conductor stringing)	Cost per Mile	325.0	32,500
Subtotal Labor/Installation	Cost per Mile	637.0	63,700
Total Transmission Line Cost	**Cost per Mile**	**1,441.2**	**144,124**
Infrastructure Costs			
Materials & Equipment			
Transformers, Series Compensation, etc.	Cost per Converter Station	17,200	34,400
Converter Station (includes ground electrode)	Cost per Converter Station	275,000	550,000
Subtotal Materials & Equipment	Cost per Converter Station	292,200	584,400
Labor	Cost per Converter Station	75,000	150,000
Total Infrastructure Costs	**Cost per Converter Station**	**367,200**	**734,400**
Services/Other Costs			
Transmission Line Services			
T-Line Management Services (Site mgmt, legal, lands, ins, PR, etc.)	Cost per Mile	26.0	2,600
T-Line Engineering, Const Mgmt, & Environmental Monitoring	Cost per Mile	52.0	5,200
Subtotal	**Cost per Mile**	**78.0**	**7,800**
Subtotal All Costs (without sales tax)	**Cost per Mile**	**8,863.2**	**886,324**
Sales Tax	**Cost per Mile**	**305.8**	**30,583**
Total Capital Cost	**Cost per Mile**	**9,169.1**	**916,907**

Annual Operating and Maintenance Costs Line Item	Unit of Measurement	Cost per Unit ($000)	Total Cost (100 Mile Line, $000)
Transmission Line and ROW			
T-Line/ROW Labor	Cost per Mile	8.3	828
T-Line/ROW Maintenance Materials	Cost per Mile	1.7	172
Insurance	Cost per Mile	1.0	100
Replacement Parts/Equipment/ Spare Parts Inventory	Cost per Mile	1.0	100
Subtotal	Cost per Mile	12.0	1,200
Subtotal All O&M Costs (without sales tax)	**Cost per Mile**	**0.0**	**1,200**
Sales Tax	**Cost per Mile**	**0.1**	**13**
Right of Way/Royalty Payments - Public land	**Cost per Mile**	**1.2**	**121**
Total with Payments	**Cost per Mile**	**1.3**	**1,334**

Source: NREL Jobs and Economic Development Impact Model (JEDI), 2017 500 kV HVDC bi-pole line estimate.

3.3.1. Summary and insights on HVDC cost trends

What has been the historical cost per mile or cost per MW-mile in developing HVDC transmission facilities in the United States?

HVDC cost per MW-mile estimates vary widely across sources. A lack of recent HVDC projects in the United States makes it difficult to ascertain the typical project costs of HVDC lines. The latest study on HVDC transmission networks (MacDonald et al., 2016) assumes a cost per MW-mile range between $700 and

$4,400. The lowest cost is achieved through economies of scale at about 1200 miles, and the study suggests that economies of scale are achieved at about 200 miles (MacDonald, et al. 2016). ETSAP provides a smaller cost estimate range, between $890 and 3,961 per MW-mile (IEA ETSAP 2014). In terms of cost per mile, ICF has seen a range between 1.17 million $/mile to 8.62 million $/mile in the literature for HVDC projects (see Figure 20 in Appendix A.3. for a cost summary).

How does this break out between fixed and variable cost (that is, costs that are independent of mileage and costs that are a function of mileage)?

HVDC lines have high fixed costs in the form of converter stations and associated equipment. Using NREL's JEDI modeling simulation (in Table 4, above) for a hypothetical 500-kV, 100-mile bi-pole HVDC line, the fixed infrastructure cost is estimated to be $734.4 million. The transmission line costs for a 100-mile hypothetical line in the example is estimated to be $144.1 million. This would translate to a variable cost of roughly $1.44 million/mile. The fixed costs of the project are roughly five times the variable costs of transmission line. In addition, the project is expected to have annual operating and maintenance costs of around $1.3 million/year.

What factors raise or reduce these costs (such as regional labor costs, geography, population density, and so forth)?

The cost of an HVDC transmission system depends on many factors, such as power capacity to be transmitted, type of transmission medium (submarine or land-based), environmental considerations, access to easements and ROWs and cost of converter stations and associated equipment. The most important cost-influencing factor is distance. Short-distance HVDC lines are typically more expensive on a unit distance (per mile basis) because of high fixed equipment costs (for example, the Hudson Transmission Project). Other factors like terrain of the path and the population density around the transmission line tend to affect the project costs. Generally, acquiring the ROWs and easement is easier for flat terrain, and areas outside of population centers and environmentally/historically sensitive areas. Therefore, the cost of such HVDC lines is also cheaper. HVDC lines configured as submarine cables are expected to be more expensive than land-based HVDC lines. Taking into account these factors, the expected cost of HVDC projects in the United States have ranged between $1.17–$8.62 million/mile (see Figure 20 and Table 6 in Appendix A.3).

What cost-related factors may constrain HVDC deployment?

The major cost item that could constrain HVDC deployment is the cost of converter stations, which could range as high as 50%–60% of the total fixed cost for an HVDC project. This makes HVDC uneconomical for some applications, for example if the line length is below a threshold distance, or if multiple offtake or delivery locations are required. Bi-directional transfers require the use of back-to-back converter stations at both the source and delivery locations, which could further increase the cost.

Other cost-related factors outside of the HVDC component costs could constrain its deployment (DOE 2013):

- **Cost allocation and regulatory issues:** FERC Order No. 1000 (FERC 2011b) requires the allocation of costs to beneficiaries. However, some projects might have system benefits such as improvements in system reliability that are difficult to quantify or incorporate into a cost-benefit analysis. It can also be difficult to determine beneficiaries where a project has cross-border impacts.

- **Difficulty in deploying multi-terminal HVDC networks:** In spite of rapid advances in HVDC technology, deploying and controlling power flows using multi-terminal HVDC networks remains cost prohibitive. In comparison, it is much easier to deploy AC solutions to achieve similar results.
- **Preference for lower cost solutions:** It is easier to permit and finance smaller projects and expenditures. This can lead to a preference for AC projects and non-transmission alternatives.
- **Lack of standardization:** Unlike AC systems, each DC project is different and requires customization, which can affect the cost competitiveness. AC systems have good interoperability, and hardware components from different manufacturers can be integrated. Hardware components for an HVDC project are typically provided by the same manufacturer.

4. Conclusions

ICF reviewed several publicly available reports and prepared case studies for three major market regions in the United States to support EIA's effort to assess the potential for HVDC transmission networks to mitigate the impacts of non-dispatchable generation technologies. Because non-dispatchable technologies such as wind and solar operate only when the indigenous resources are available, they create dispatchability challenges for system operators. HVDC lines can mitigate the impact of non-dispatchable resources because DC power flows are controllable, they have low losses over long-distance transmission, and they are they are decoupled from AC systems and are suitable for asynchronous interconnection. ICF also evaluated recent cost trends associated with HVDC projects.

ICF's research and case study analysis identified sources that addressed key questions of interest to EIA:

- Studies of existing systems and projects under development demonstrate that HVDC can be effective in mitigating these impacts on non-dispatchable generation.
- HVDC tie lines between balancing authorities are sufficient to transfer system impacts from host to client regions. The non-dispatchable generators do not have to be directly connected to the client region.
- Penetration levels of non-dispatchable generation at which HVDC solutions would be expected to be deployed vary with factors such as the robustness of the underlying transmission network, the mix of generation resources, availability of flexible resources, and the nature of the ties to neighboring systems.
- Other parameters such as distance between source and sink, potential alternative solutions, the nature of the application, and the regional systems within which the host and client areas are located can influence the deployment of HVDC. HVDC is better suited than AC for submarine applications and for interconnection of asynchronous regions.
- The cost of converter stations and associated equipment can constrain the deployment of HVDC for some applications.

Some issues are not fully addressed in the reviewed literature and additional research and analysis will be required to develop further insights:

- Whether some system configurations and topologies of AC and DC interfaces are more effective at mitigating some or all impacts from non-dispatchable generation
- Penetration levels at which HVDC would be required for specific systems, and quantitative measures of the extent to which regional and other factors can affect penetration level
- The extent to which the type of non-dispatchable technology deployed, the share of conventional generation technologies, and/or other regional characteristics affect the penetration level
- Specific limitations to the ability of HVDC to mitigate intermittency impacts

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Appendices

A.1. Case Studies of Potential Implementation of HVDC Solutions

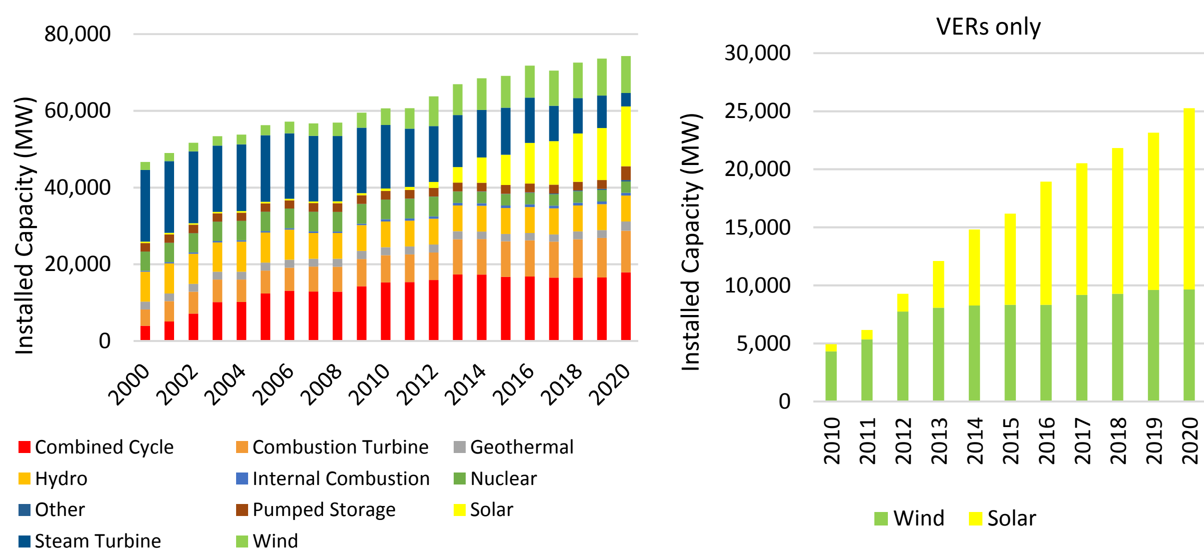
To address the questions raised in the project scope, ICF adopted a case study approach to identify the issues and challenges of incorporating HVDC solutions in addressing the problem of renewable intermittency. The three shortlisted case studies focus on regions with a considerable share of renewable penetration—CAISO (California), ERCOT (Oklahoma-Texas Panhandle region), and MISO (northeastern region of Iowa and Minnesota).

A.1.1. TransWest Express Project in CAISO

Renewable Penetration Trends in CAISO

California has been on the forefront of renewable energy deployment in the United States. California's original RPS target called for 33% renewables procurement by 2020. The share of VERs is expected to increase from 19 GW in 2016 to 25.2 GW in 2020. This is expected to meet the 33% RPS target by 2020. The share of VERs is expected to be a high of 34% by 2020. Recently, the state increased its RPS target to 50% by 2030.[12] This calls for a major ramp up in procurement of electricity from renewable resources in the near future. Potential HVDC projects capable of delivering renewable power to the state could help California to meet its 50% RPS target.

Figure 8. Installed capacity trends for CAISO (existing and planned)



Source: Compiled by ICF using SNL data.

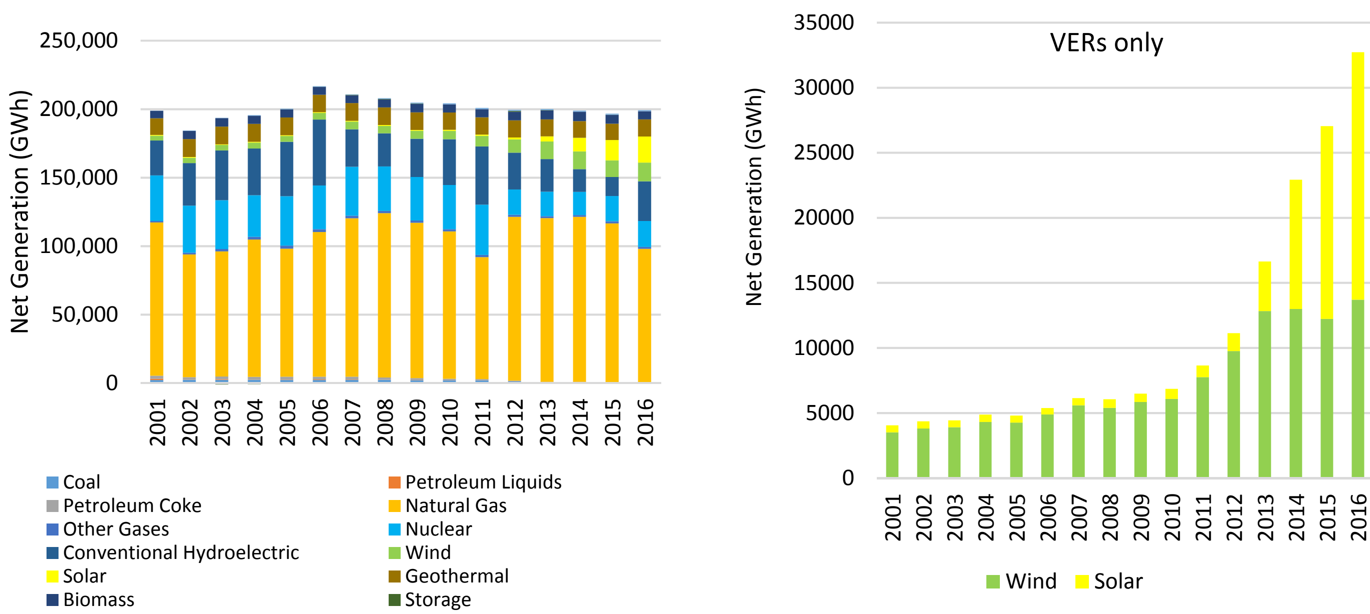
Note: Future capacity estimates are based on actual planned and under-construction projects.

Figure 9 denotes net generation trends in California for recent years. The share of generation output from VERs in California is gradually increasing from 2.0% in 2001 to 16.3% in 2016. The penetration level is only

[12] California passed legislation SB 350 in October 2015, which requires retail sellers and publicly owned utilities to procure 50% of their electricity sales from eligible renewable energy resources by 2030. The interim target for 2020 is still 33% RPS target. For more information, see California Energy Commission Renewable Portfolio Standards.

expected to increase in the near future with increasing VERs. CAISO started considering renewable integration measures after 2010 when the annual penetration levels were at 3.3%. Several key initiatives like the energy imbalance market (EIM) and the CAISO flexible ramping product were introduced in the last two years when the penetration levels of VERs in California was about 14%–16%.

Figure 9. Recent net generation trends in California (GWh)



Source: Compiled by ICF using EIA data.[13]

CAISO's current efforts to integrate VERs provide a good case study template for other regions that will be addressing these matters in the coming years. CAISO is taking certain steps to address the challenges associated with integrating a large share of VERs. CAISO introduced wholesale market design changes in 2009. Some of the other incremental changes introduced by CAISO to facilitate renewables integration include

- CAISO introduced a region-wide EIM in 2014. EIM is a real-time market involving utilities across eight western states that trades the difference between the day-ahead forecast and the actual amount of MW resources to meet the system demand. EIM enables wider access to generation and transmission resources to meet fluctuations in real-time system demand. This would also enable individual balancing authorities to address the problems of renewable intermittency and ensure overall grid reliability (Western EIM 2017).
- CAISO lowered the energy bid floor for renewables from -\$30/MWh to -\$150/MWh for the first year and to -\$300/MWh in the following year. The objective was to provide additional incentive for market participants, including VERs to submit decremental bids enabling the ISO to manage over-generation and congestion more efficiently and transparently (CAISO 2017b).
- CAISO revised the bid cost recovery netting methodology so that the bid cost recovery amounts calculated for the day-ahead and real-time markets, respectively, are not netted together (CAISO 2017b).

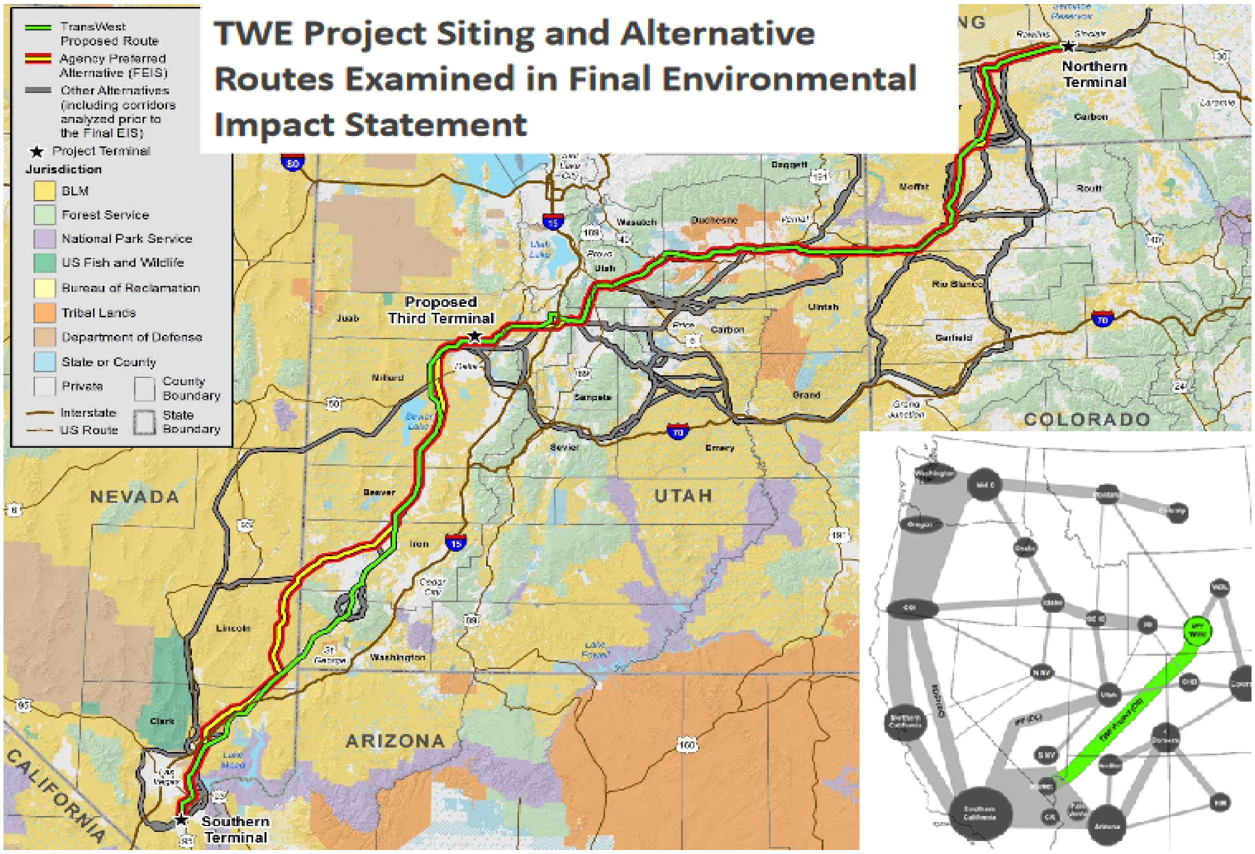
[13] See EIA Electricity Data Browser.

- CAISO modified its payment rules for startup and minimum load costs, unrecovered energy bid costs, and residual imbalance energy for generators. These changes are aimed at streamlining uplift payments and eliminating the potential incentives for adverse market behavior by some generators who previously could expand bid cost recovery or residual imbalance energy payments (CAISO 2017b).
- In 2016, CAISO introduced two flexible ramping products—Flex Up and Flex Down—in its real-time markets. These products are designed to enable CAISO to procure sufficient ramping capability via economic bids. These products provide additional upward and downward flexible ramping capability to account for uncertainty in net system demand due to renewable intermittency (CAISO 2017).
- In response to FERC Order No. 755 regulation (FERC 2011a), CAISO modified its existing capacity payment for frequency regulation in its wholesale markets. CAISO has introduced and implemented a two-part structure to establish prices for regulation capacity and mileage, which is a performance-based payment (CAISO 2017 c).

TransWest HVDC Project in Western Interconnect

As mentioned earlier, HVDC projects can help California in achieving its 50% RPS target. In CAISO, there are now two operational HVDC lines—Pacific Intertie with BPA and Trans Bay Cable in the San Francisco area. The Trans Bay Cable (400 MW, 200 kV) is primarily a merchant congestion relief project for delivering power to the San Francisco area. The Pacific Intertie (3800 MW, 500 kV) is the oldest and largest HVDC link in the country meant to remote generator interconnection between BPA and CAISO. In addition to these existing lines, the TransWest Express LLC is proposing to build a 3000 MW, 600 KV TWE line to deliver wind power from southern Wyoming to California. This project has been proposed since 2005. Its developers are actively pursuing this project and recently secured approvals from the U.S. Department of Interior Bureau of Land Management (BLM), Western Area Power Administration, and U.S. Forest Service following a review of the project's final Environmental Impact Statement (TransWest Express 2017). ICF chose to focus on this project since it highlights the factors that come into play when considering HVDC projects that address renewable integration issues.

Figure 10. Proposed TransWest project in Western Interconnect



Source: TransWest Express, LLC (2016).

The TWE project is a proposed extra-high-voltage transmission line connecting the wind resources in south-central Wyoming to southern Nevada, which would interconnect to CAISO balancing authority (TransWest Express 2017). It consists of 725 miles of HVDC lines between Sinclair, Wyoming, and Marketplace Hub-Eldorado substation in Boulder City, Nevada. The line is rated to deliver approximately 4,000 MWh of power annually for every 1 MW of installed capacity. In total, the line can deliver up to 12,100 GWh of power annually to southern California and desert southwest region. The project is expected to interconnect wind power plants in the southwest Wyoming region through the existing AC network.[14] TransWest Express affiliates are currently developing the 3,000-MW Chokecherry and Sierra Mandre Wind Energy Project and a potential natural gas generator located near the project's Northern Terminal. [15] The wind generator project has received BLM approval for its Environmental Impact Statement for Phase I of the project. The host region is part of the NTTG transmission planning group while the client region is part of the WestConnect planning area. The wind site is expected to contain approximately 1,000 wind turbines of 3 MW-rated capacity each and spread over 210,000 acres (Power Company of Wyoming 2017). Power generated from the project will likely be routed to one or more of up

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[14] Based on publicly available sources, it is not clear if the TWE project has a dedicated collector system for its Northern Terminal end in Wyoming. ICF assumes the wind generators interconnect to the existing AC grid in the region. It should be noted that TWE was part of a Wyoming Wind Collector and Transmission Task Force of WAPA and that there were conceptual plans for a Wyoming collector and transmission system.

[15] See Power Company of Wyoming, LLC.

to five potential transmission lines or an existing transmission line. Both these alternatives were assessed in the Environmental Impact Statement .

Insights from TransWest Case Study

The feasibility of the TWE project has been assessed by various regional planning entities like WECC, NREL, and Northern Tier Transmission Planning Group. Preliminary assessment by these entities confirms that the project can cost-effectively interconnect remote renewable energy to satisfy a portion of California's renewable needs. Although the 50% RPS target was not explicitly assessed in these studies, it is expected that this project would make more economic sense with an increased RPS target. WECC's 2011 Regional Transmission Plan highlighted the economic benefits of tapping Wyoming's high-capacity wind energy (Class VI and VII wind resources) to meet California's RPS goals (WECC 2011). The study estimated that the TWE project can potentially save California ratepayers $600 million/year (based on 2011 vintage assumptions). The NREL Wyoming-California study assessed the economic benefits of a transmission corridor between the two regions (akin to an HVDC transmission project) (Corbus, et al. 2014). The study found that the economic benefit of such a transmission line is likely to outweigh the costs, with benefit-to-cost ratios ranging from 1.6 to 3.6. The Corbus et al. study (2014) compared scenarios wherein the 33% RPS requirement for California is met by in-state resources versus an option to import up to 12,000 GWh/year from Wyoming in addition to local in-state resources. The import option would correspond to a 3,000 MW HVDC line from Wyoming with an average annual capacity factor of wind resources at 46%. Factoring in line losses, the annualized transmission costs under these assumptions is estimated to be around $29 per MWh delivered (2014 $). Based on NREL study, the import scenario show economic benefits exceed costs in the range of $2.3 billion to $9.5 billion over 50 years on a net present value basis (2014 $ basis). The benefits were primarily due to the difference in generation cost for the various renewable technologies studied, strongly influenced by the fact that Wyoming has some of the highest wind capacity factors in the United States. The study also found the LCOE of Wyoming wind delivered by an HVDC project to be the lowest among all generation options, even lower than in-state wind and solar resources. The study also found modest production cost savings of about $31 million/year (or 0.3$) for the entire WECC region as the result of imports from Wyoming. The savings accrue because of lower startup costs of wind units. The imports also resulted in lower wholesale prices in southern California areas that are closer to the Marketplace Hub in Nevada. The study also found that the California–Wyoming transmission corridor helps to avoid other transmission projects, which would have been required when relying solely on in-state renewable resources alone.

It should be noted that none of the publicly available studies has looked at the detailed reliability implications of the proposed TWE project. In addition, none of the available studies has modeled 50% RPS target by 2030 as an explicit scenario assumption. Nevertheless, the case for TWE project is expected to improve under this revised RPS target. None of the studies has indicated any adverse conditions at the host or client regions because of the proposed HVDC interconnection. The NREL study did perform a production cost modeling using the Plexos modeling platform and found no major reliability implications of interconnecting the project to Southern California and Desert Southwest region. Currently, WECC is implementing the Phase 2 Path Rating Study and Southern Terminal system impact study for the project (TransWest Express, LLC 2016). Since it is an interregional transmission project, it is being considered in the current planning cycle by transmission planning entities of CAISO, WestConnect, and NTTG. CAISO's Transmission Planning Process for 2016–17 incorporated the TWE project in its assessment. The results of the assessment are yet to be finalized (at the time of writing). TransWest is also requesting cost allocation from CAISO and WestConnect transmission planning entities. In the future, TransWest has indicated that it may apply for cost allocation from NTTG as well. As a configuration alternative, TransWest is proposing to build a third terminal to connect to the 345 kV bus at the Intermountain Power Project in Delta, Utah, and to use 500 kV AC technology in lieu of HVDC for the segment from Wyoming to Utah and/or the segment from Utah to Nevada (TransWest Express, LLC 2016). TransWest is also considering implementing the project in phases, with building a 3,000 MW line and only 1500 MW of terminal capacity (at both ends) and add in parallel a 1,500 MW of terminal capacity later. TransWest is also exploring variants of this phasing plan with initial capacity between 1,500 MW and 2,500 MW and shortening the period between initial and final build out. Currently, TransWest plans to continue development activities including state and county permit, private ROW acquisition, transmission planning assessments, project financing, and securing interconnection/transmission capacity agreements.

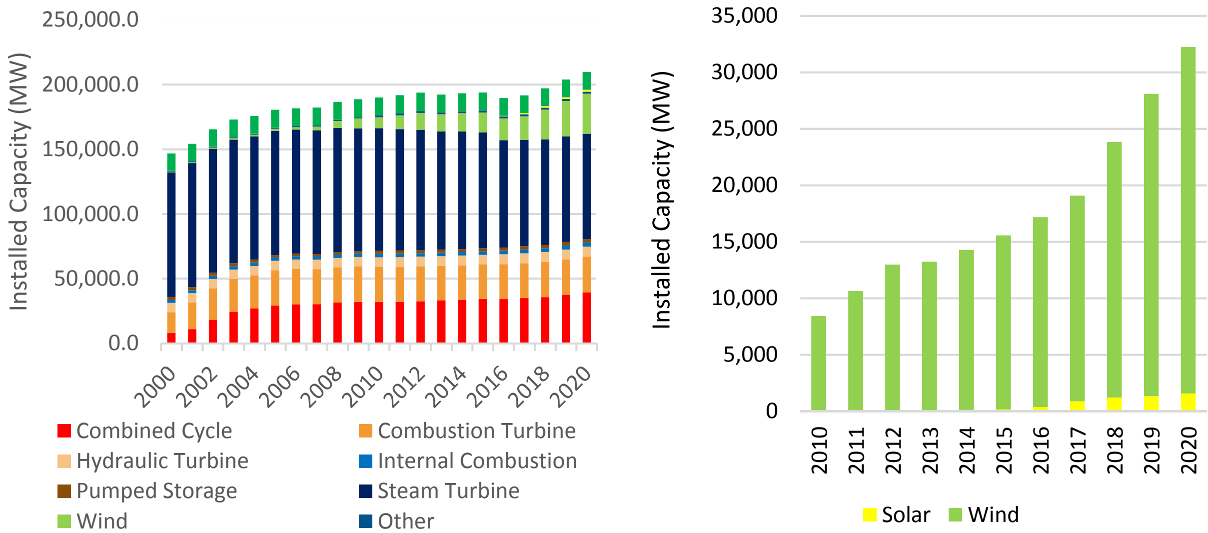
The TWE case study highlights the advantage of HVDC when connecting renewable energy sources to distant load centers. TWE will deliver power generated in Wyoming to load centers more than 700 miles away. It also facilitates the direct connection of demand and supply sources in different balancing authorities that are not even contiguous. The impact on the underlying grid in reduced because HVDC is fully controllable and decoupled from the AC system. TWE also shows that HVDC can transfer system impacts from host to client regions even if the non-dispatchable generation is not directly connected to the client region. As outlined in TransWest Express LLC report (2010), the loss of a single pole of the TWE project will affect the interconnected system within acceptable parameters until generation tripping can occur. This implies that the TWE wind resources will be connected to the Wyoming grid, which is the host region, and not directly to the client. TransWest Express LLC (2010) reiterates this point, and shows that despite the advantages of HVDC, protection schemes might sometimes be required to resolve dynamic reliability problems that could occur in the host region under certain emergency conditions. Because of the size of the project within the relatively weak Wyoming grid, the simultaneous loss of both circuits of TWE could lead to widespread system outages. TWE would have to be planned to minimize the likelihood of the simultaneous loss of the two circuits.

A.1.2. MISO Conceptual HVDC Network Case Study

Renewable Trends in MISO

In the case of MISO and the upper Midwest region, the growth of VERs has been driven by wind energy as the region has highly favorable conditions for wind generation (unlike in CAISO's case with mostly solar power generation). In particular, Minnesota has set a 25% wind-based generation target by 2025 and the largest provider, Xcel Energy has set a 30% wind-based target by 2020. Iowa has set a specific target for all IOUs to procure at least 105 MW of renewable generation. VER capacity is expected to increase from 17.1 GW in 2016 to 32.2 GW in 2020. The vast majority of this capacity is coming from wind facilities. Even solar energy is also expected to show a small upward trend in installation in the coming years. The share of VERs is expected to increase from 9% in 2016 to 15.4% in 2020. Figure 11 shows the installed capacity trends within MISO, as well as the VER installed capacity between 2010 and 2020.

Figure 11. Installed capacity trends in MISO

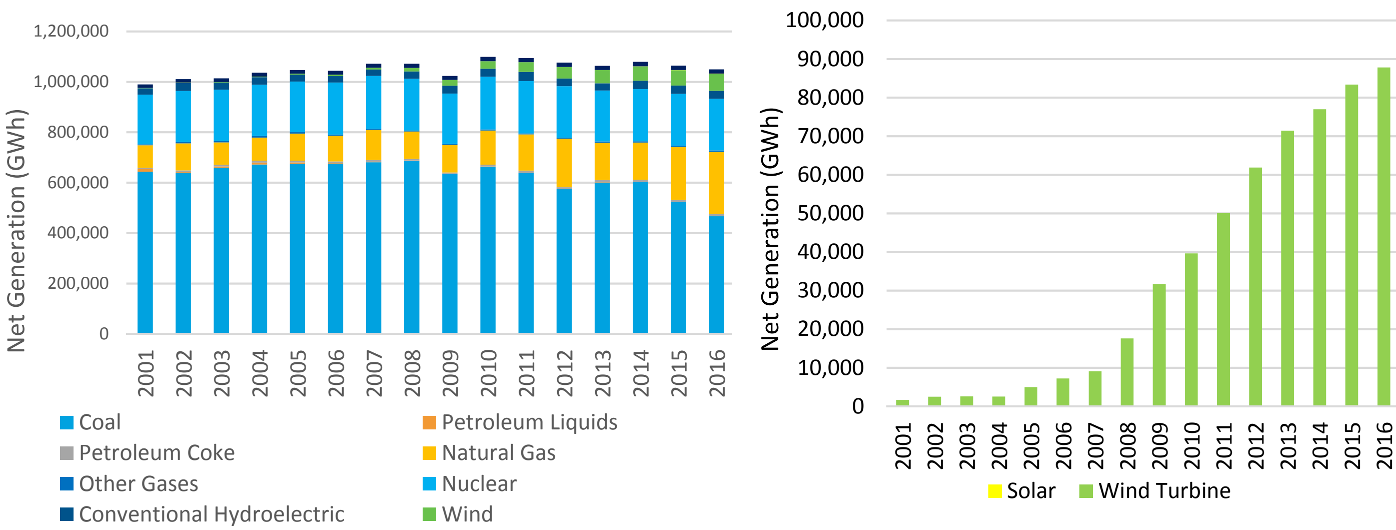


Source: Compiled by ICF using SNL data.

Note: Future capacity is based on actual planned and under-construction projects.

Figure 12 shows the net generation trends within MISO from 2001 to 2016. VER generation share has increased from 0.1% in 2001 to 5.11% in 2016. This is attributed solely to wind energy, as solar generation share is insignificant. The increase in wind capacity over the next few years (Figure 11) combined with the forecasted reduction in coal capacity is expected to cause an increase in wind generation share, as mandated by the RPS requirements of most MISO member-states.

Figure 12. Recent historical net generation trends in MISO (GWh)



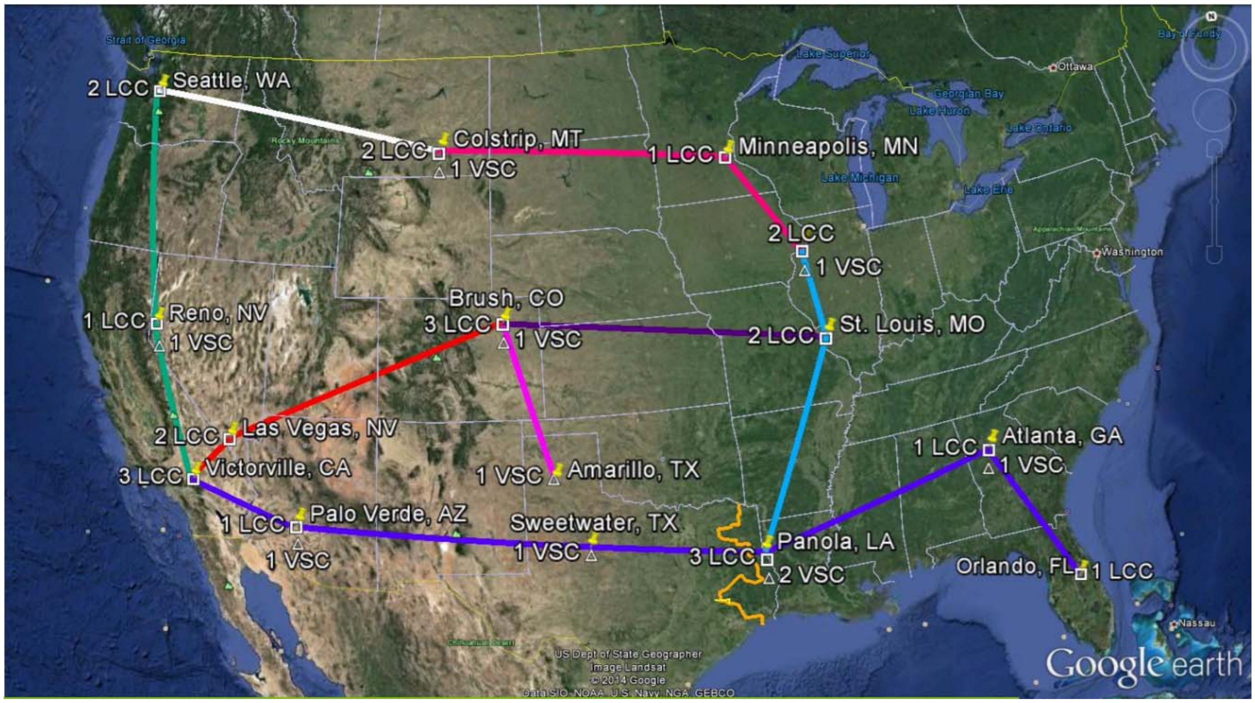
Source: Compiled by ICF using SNL.

Case Study of MISO's Conceptual HVDC Network

In 2014, MISO started an initiative to assess the feasibility of using HVDC lines to interconnect the three grid networks in the United States and facilitate greater power exports from MISO region to the rest of the country. MISO published an HVDC network study in 2014 in which the value of creating a national HVDC network was assessed (Osborn, Orser and Waight 2014). The report identified the following factors as major drivers behind the project: load diversity, frequency response, wind/solar diversity, and other benefits like supply of clean renewable power to remote regions. Load diversity is the interregional transport of generation capacity resulting from differences in load profiles between the host and client regions. The load profiles among regions vary because of time differences, nature, and composition of load, climate factors, and local/regional weather conditions. For example, the spare capacity in WECC during off-peak hours can help to serve demand in PJM if the two regions are interconnected by a direct HVDC line. Using MISO's conceptual HVDC Network (shown in Figure 13), the study identified close to 35 GW of potential load diversity (or spare capacity). Frequency response is seen as another key benefit from an interregional HVDC network. The MISO study identified potential value in distributing Resource Contingency Criteria between HVDC network participants. The HVDC network helps to share frequency response reserves through interregional power transmission. Additionally, VSCs help to facilitate fast response products like frequency response and regulation. The study identified up to 3 GW of reserves for frequency response that could be shared between the three grid interconnections. The benefits of such reserves included deferred cost of procuring additional frequency response products and premiums in the form of efficient frequency response. The HVDC network would also help to tap into the wind/solar diversity benefits across the regions. The network could facilitate efficient dispatch of renewable generation and mitigate renewable curtailments in host regions. Other benefits include a reduced ramp rate for host/client regions, reduced variability from VERs and, as a consequence, a potentially increased capacity credit for such resources. Finally, an HVDC network also offers other energy-based benefits such as energy arbitrage across networks and cost-effective compliance with state RPS standards (in some cases).

According to the study, the monetary value of the potential benefits is estimated to be $45.3 billion, with benefits accruing due to load diversity ($21 billion), frequency response ($9.8 billion), wind diversity ($2.2 billion), and other energy benefits ($12.2 billion) (all in 2014$) (Osborn, Orser and Waight 2014). The conceptual network consists of 7654 miles of new lines, 22 LCC type converter stations and 10 VSC-type converter stations. The network (Figure 14) would deploy both LCC (5400 MW) and VSC (2200 MW) converter-types, with a maximum of three terminal LCC links at each node (VSC taps in parallel). It includes three lines connecting the eastern and western regions, with a total transmission capacity of 15 GW. The total cost for a project of this magnitude is estimated to cost $36.2 billion. It would require a total of 7654 miles of HVDC lines, which cost approximately $3 million per mile, for a total line cost of $23 billion. The 22 LCC terminals would cost $10.4 billion ($472 million per terminal) and the 10 VSC terminals would cost $2.9 billion ($285 million per terminal). The overall cost of the line is expected to be $36.2 billion. Considering the benefits of such as network at $45.3 billion, the overall benefit-cost ratio is expected to be 1.25.

Figure 13. Conceptual HVDC network assessed by MISO study

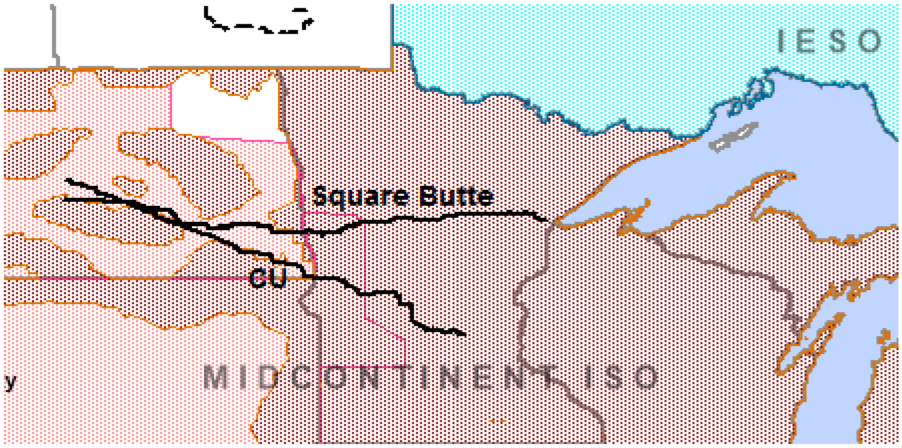


Source: Osborn, Orser and Waight (2014).

Square Butte HVDC

In the previous case study, ICF examined the benefits of a conceptual HVDC network for the region. ICF also found one case study wherein an existing HVDC line was being reconfigured for renewable integration. The Square Butte HVDC line was commissioned in 1977 to connect the Milton R. Young Power Plant (a coal unit) in Center, North Dakota, with the Arrowhead Converter Station in Hermantown, Minnesota. The 465-mile, 250-kV transmission line was initially dedicated for transferring electricity generated at the coal plant however, the coal-fired generating unit in North Dakota is slowly being retired, opening room for renewable energy transmission. In 2009, the HVDC line and its associated facilities were acquired by ALLETE Inc. (d/b/a Minnesota Power). The acquisition of the Square Butte facilities by ALLETE in 2009 for $71.5 million, is part of ALLETE ’s plan to comply with Minnesota’s RPS requirements, which set a minimum of 20% renewable energy generation or procurement by 2020 and 25% by 2025 (FERC 2009). ALLETE has indicated that there are plans to use the HVDC line to transport increasing amounts of wind energy while gradually phasing out coal-based electricity (ALLETE 2010). This wind energy will be supplied by ALLETE’s Bison Wind Energy Center, which provides 496 MW of installed capacity.

Figure 14. Square Butte HVDC line



Source: Created by ICF using ABB Velocity Suite.

Insights from HVDC Case Studies in MISO

The different benefits associated with a network of HVDC lines can be ascertained based on the two case studies. To summarize, the key benefits of an HVDC appear to stem from load diversity, provision of frequency response, wind/solar diversity and energy-related benefits. The MISO HVDC network study was the first conceptual study of an HVDC network for the United States. This has also been explored by MacDonald et al. (2016) in the context of renewable integration and deep emissions reductions from the power sector in the United States. In addition to this, NREL, under a regional partnership with DOE-Grid Modernization Initiative, is currently assessing the value of augmenting interconnection seams between Eastern and Western Interconnections in the country (Bloom, Interconnections Seam Study 2017, NREL 2017). Currently, the two grid networks are interconnected by interties that can enable about 1,400 MW of electricity to flow (see Appendix for the list of interties). The transfer capability is minuscule compared to the size of the networks they interconnect—around 1,005 GW of operating capacity in both grid networks (excluding ERCOT). The NREL study (2017) proposes to implement both power flow and production cost modeling of different scenarios of HVDC networks and intertie augmentation. One of the scenarios assessed in the study includes the conceptual network proposed by MISO.

The simulated costs and benefits of MISO's conceptual HVDC network were summarized in Section 2 of the report. The qualitative benefits of such a network are summarized below for reference. The case for an interregional HVDC network is primarily driven by load diversity between regions caused by differences in time zones, load profiles, composition of demand, climate, and local weather trends. By using interregional HVDC lines, the spare capacity in one region can serve the load in the other region. The value of such links is higher with greater line distance. Such lines obviate the need for new capacity (in MISO's assessment it obviated the need for nearly 30 GW of peak generation). The other major benefit is the provision of frequency response service through interregional HVDC lines. The benefit is in terms of procuring frequency response resource remotely and the premium in providing such responses cost-effectively. The sharing of frequency response reserves through interregional networks also improves bulk system reliability. The HVDC link also helps in cost-effectively smoothening and dispatching VER outputs in the host region. Using long-distance interregional HVDC links, the renewable resources in one region (host region) can potentially supply loads in the client region, irrespective of the system load conditions in the host region. The MISO study shows that when HVDC flows are dispatched on interregional basis, the economic curtailment of renewable resources in the host region can be minimized. The HVDC network can also lower the reserves used by system operators to account for renewable intermittency. The HVDC links may contribute to a higher capacity credit of wind/solar resources through geographic diversity (that is, individual VER generator outputs are not correlated). It is also possible to tap into the energy arbitrage across the grid networks/regions under favorable conditions using interregional HVDC lines. The HVDC lines also help individual states to meet their RPS targets cost-effectively if delivering renewable power. In addition, HVDC lines can also operate at overload capacity (typically up to 115% of the rated capacity) for a limited period. This would enable system operators to implement mitigation measures in response to system contingencies.

The MISO HVDC conceptual study and the Square Butte HVDC demonstrate that HVDC is effective in transferring system impacts from host to client, even in cases where the non-dispatchable generation is not connected directly to the client region. In both cases, the wind resources would connect to the host region, and the HVDC line would facilitate integration with the client region. The conceptual study and the project both show the advantage of HVDC for transfers of power over long distance. The Square Butte HVDC line is more than 465 miles long, while some segments of the HVDC conceptual study are more than 800 miles long. The conceptual study also demonstrates the advantage of HVDC in connecting supply and demand regions in different interconnections.

A.1.3. SPP's Clean Line Project Case Study

Renewable Penetration Trends in SPP

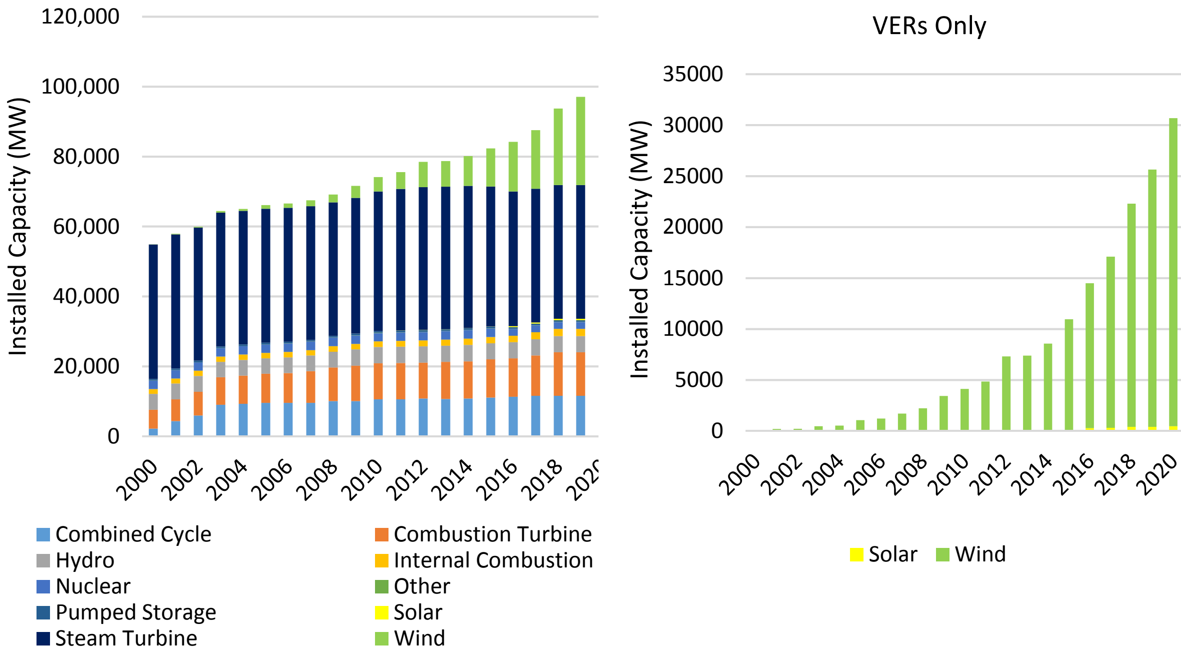
Southwest Power Pool (SPP) is emerging as the next market leader in wind development after the ERCOT West region. The predominant VER resource in the SPP region is wind. SPP is uniquely positioned to facilitate greater integration of wind resources in the coming years. The geographic footprint of SPP covers some of the best wind resource sites in the country today. Recent estimates have shown that nearly 16 GW of wind is in operation in SPP with an additional 38 GW of wind projects in different stages of development (SPP 2017). A recent wind integration report for SPP (2016) has determined that up to 60% wind penetration levels can be reliably accommodated in SPP (SPP 2016a). In fact, SPP became the first system operator in North America to serve more than 50% of its load at a given time using wind energy alone (with a record wind penetration of 54.2% on March 19, 2017) (Walton 2017). Wind energy is already a significant part of the region's generation portfolio accounting for 20% of the total generation and 17% of the total installed capacity in 2016.[16] The share of installed capacity of VERs (mostly wind) has increased from 5.6% in 2010, and is expected to reach a high of 30% by 2020 (see Figure 15). The net generation trends for SPP region are shown in Figure 16. The annual share of output from VER resources (mostly wind) is expected to increase from 4.2% in 2010 to 14.6% by 2016. During high wind output months (spring and fall), the share of wind generation in SPP is expected to reach as high as 50%. To date, no other system operator in the country has managed to serve successfully as high a percentage of its load using wind generation.

The bulk of wind generators are located in the western Kansas, western Oklahoma, and the Texas Panhandle region of SPP. This region is called the "wind alley" region of SPP. Out of the 38.7 GW of proposed wind projects in SPP, nearly 26 GW are located in the states of Kansas, Oklahoma, and Texas.

[16] Discussions on SPP power market trends and data are sourced from SNL and ICF calculations (unless stated otherwise).

Interconnection is being sought for nearly 15 GW of wind projects in Oklahoma alone (SPP 2017) . For the entire SPP region, 4.4 GW of wind projects with approved interconnection agreements are expected to come online by 2018. There is additional scope for wind penetration since the share of coal continues to decline in SPP's generation portfolio mix in recent years. In 2016, roughly 50% of generation in SPP was sourced from coal-based power plants. In the future, this generation share is likely to decline even more, offering additional opportunities for further wind penetration and consequently the need for intra and interregional HVDC links.

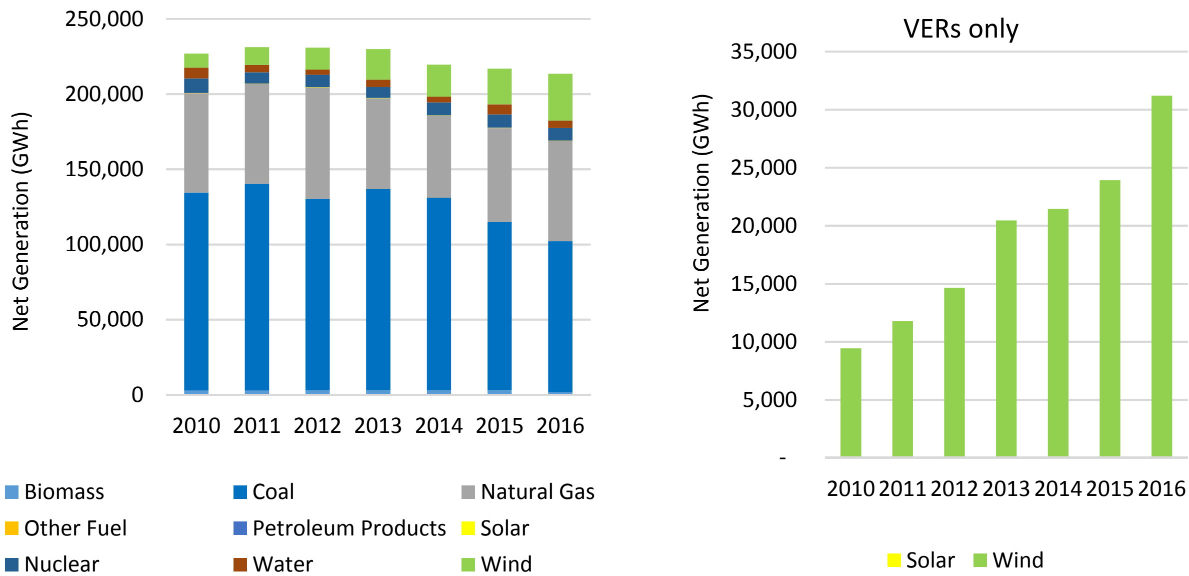
Figure 15. Installed capacity trends in SPP



Source: Compiled by ICF using SNL data.

Note: Future capacity is based on actual planned and under-construction projects.

Figure 16. Recent historical net generation trends in SPP



Source: Compiled by ICF using SNL data.

Wind Integration Challenges in SPP

Today, SPP is in a position to reap the benefits of wind integration because of the proactive wind policies and strategies adopted in the past. As part of its Balanced Portfolio initiative, SPP invested in transmission upgrades during the period from 2012 to 2014 that set the stage for the increased penetration of wind seen today (SPP 2009). SPP also implemented the Integrated Marketplace in 2014 that expanded the market footprint considerably, ushered in improved interregional coordination, and better integration of renewable generation.[17] Specifically, SPP's Integrated Marketplace included a day-ahead market with transmission congestion rights (TCRs); a reliability unit commitment process; a real-time balancing market; a market price-based ancillary and operating reserve market; and a unified balancing authority setup for the whole of SPP service territory. Specifically, prior to SPP's Marketplace, Dispatchable Variable Energy Resources (DVERs) were subject to curtailment in the EIM based on impacts to a constraint and transmission service priority. Implementation of the SPP Integrated Marketplace introduced rules so that DVERs could be dispatched down based on offers and locational marginal prices in a manner similar to other dispatchable resources.

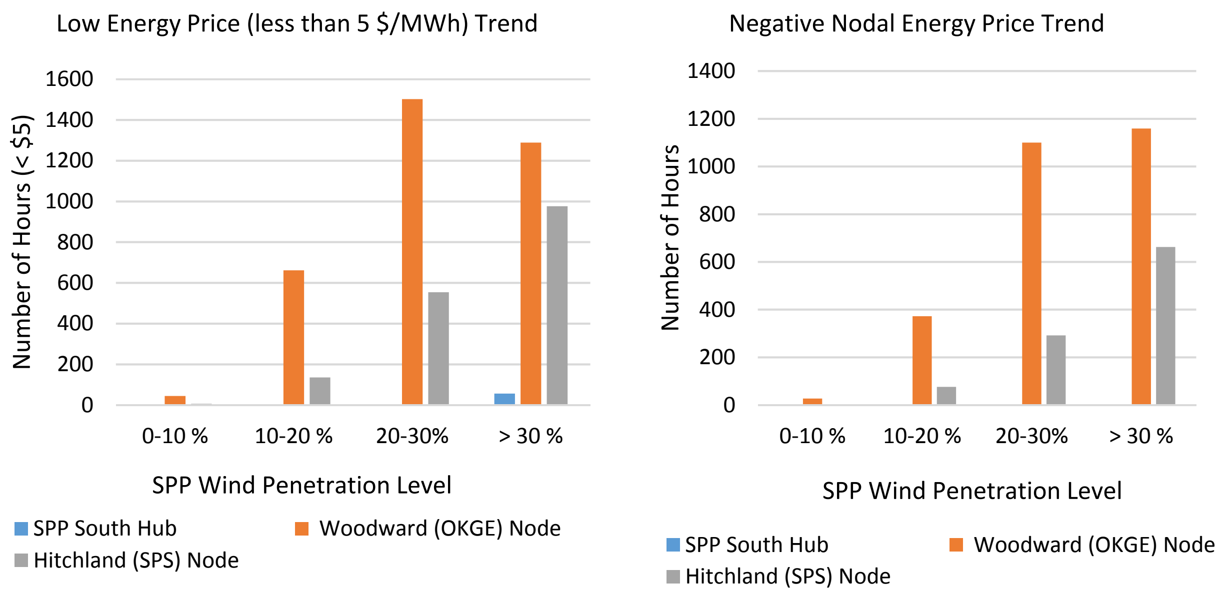
The rapid growth of wind generation projects has brought a unique set of challenges to SPP's wholesale markets and operation. Since many of the existing and planned wind projects are located in the "wind alley" region of SPP, the congestion trends in the region are being exacerbated. Typically, with transmission constraints the local generation tends to get bottled up, resulting in low or negative nodal prices. In 2016, the Woodward node (Oklahoma Gas and Electric [OKGE] load zone) experienced 3496 hours of low nodal prices (less than 5 $/MWh).[18] Likewise, the Hitchland node (Southwestern Public

[17] For more information, see Southwest Power Pool Integrated Marketplace.

[18] The node is located near Woodward, Oklahoma, in Oklahoma Gas & Electric (OGE) service territory.

Service [SPS] load zone) experienced close to 1670 hours of low nodal prices. Low nodal prices are beginning to be reflected in the SPP South Hub prices as well.[19] In 2016, the number of hours with low energy prices increased to 60 hours as compared to 18 hours in the previous year. Negative pricing is also on the rise at individual nodes. Typically, at higher wind penetration levels, the number of negative hours tend to be higher. In 2016, negative prices were observed in individual nodes like Woodward (OKGE) and Hitchland (SPS) starting at a wind penetration levels of 20% and beyond. In 2016, the Woodward node (OKGE) had a total of 2658 hours of negative prices while the Hitchland node had a total of 1030 hours of negative prices. If the current congestion trends continue, the South Hub prices could experience sustained negative prices in the future.

Figure 17. Nodal and hub pricing trends in SPP "Wind Alley" region



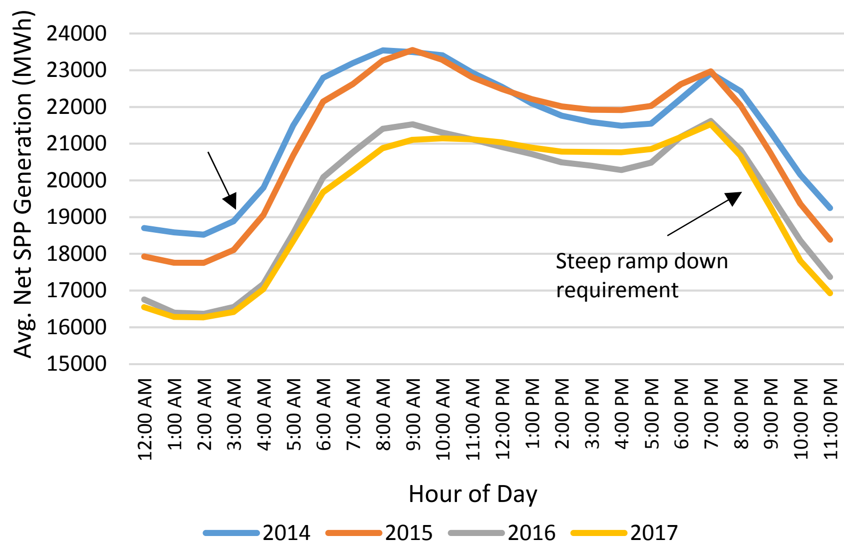
Source: SPP Marketplace.[20]

Note: Day-ahead energy prices are represented here.

SPP is likely to face system ramping issues with higher levels of wind penetration in the region. Ramp rates play a crucial role in market operations because they place limits on how quickly a system operator can respond to changes in system load. Wind generation is typically higher during the night when the system demand is low. Therefore, the net generation from other dispatchable technologies needs to ramp up during the day to meet the system demand. Subsequently they need to ramp down in the evening to facilitate wind dispatch. There was a slight increase in up and down ramp deficiency in 2016, especially for periods of higher wind generation and relatively lower demand (SPP 2016b). In 2016, the SPP system faced an average ramp up requirements of close to 4000 MW in a four-hour period in the morning (from 4:00 a.m. to 8:00 a.m.). Likewise, there is a ramp-down requirement for the evening hours starting at 7:00 p.m. and going to 11:00 p.m. In 2016, the SPP system faced an average ramp-down requirement of close to 5000 MW in this four-hour block. With increasing wind penetration, the ramping requirements are likely to go up in the near future.

[19] The node is located near Hitchland, TX in Southwestern Public Service (SPS) territory.
[20] See Southwest Power Pool OASIS.

Figure 18. Average net generation profile curve for SPP by the hour of the day (a typical spring week in March)



Source: SPP Marketplace.

Note: Net generation includes generation from dispatchable units (without wind and solar).

To address these challenges, SPP has been implementing a number of incremental mitigation measures in terms of market reforms and operational practices. In 2015, SPP implemented its Regulation Compensation market design in compliance with FERC Order No. 755 (FERC 2011a). The revised design includes additional payment to market participants based on changes in energy output for regulation deployment in real-time markets (SPP 2014). The new regulation product is set to offer the highest mileage offer (that is, price for expected performance) of any resource cleared for regulation service. This is expected to boost the participation of generator resources in the regulation market, thereby facilitating greater penetration of wind resources. Cumulatively, these policies helped in reducing wind curtailments and increasing dispatch from wind units in the region.

To accommodate the expected future wind growth, the SPP and other market participants are exploring a portfolio of options ranging from sponsored transmission solutions to SPP implementing improved market operational practices. Absent new demand or consumers, there may not be enough load appetite for wind projects in the pipeline. Consequently, intra- and interregional HVDC lines may offer the suitable external markets for these wind projects. As an immediate mitigation measure to relieve transmission bottlenecks in the "wind alley" region, the congestion relief projects identified in recent SPP Integrated Transmission Planning reports are being planned and implemented. For example for relieving the Woodward area flow gate, SPP has identified a second 345 kV Matthewson-Tatonga line and an extra high voltage phase shifting transformer at Woodward (SPP 2016a). This is expected to relieve the bottlenecks and facilitate greater dispatch from the planned wind projects in the region.

In terms of market operational practices, ICF identified two measures that could encourage greater wind penetration. The provision of mileage-based regulation compensation is expected to incentivize resources to participate in the ancillary services market. With greater participation of generator resources in these markets, the scope for further wind penetration increases. The *Wind Integration* report calls for changes in operational dispatch practices and transmission improvements to alleviate these bottlenecks (SPP 2016a). The report recommended installing voltage reactive support capabilities for existing wind farms, accelerating the Integrated Transmission Planning projects in the SPP queue, and enhancing operations and utilizing real-time monitoring tools (using PMU and other software applications) to achieve sustained higher wind penetration levels (SPP 2016a).

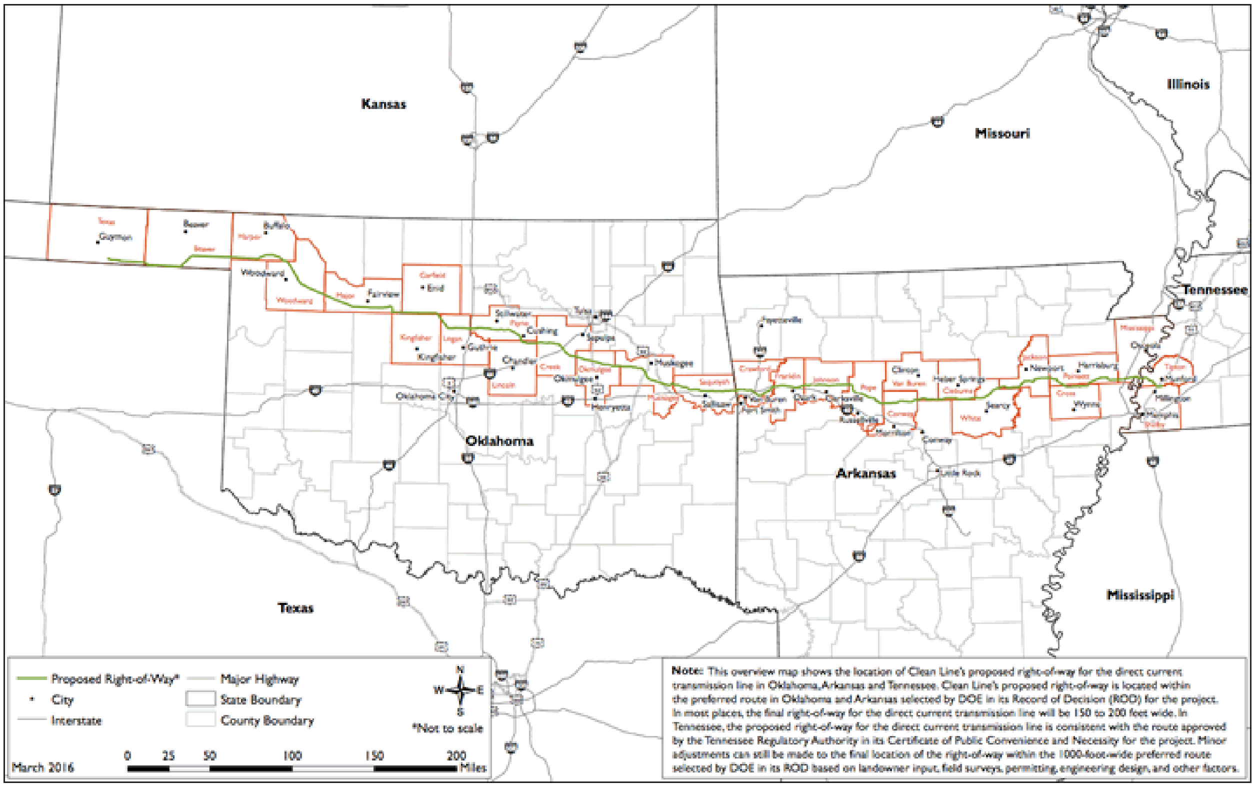
The other key issue affecting wind development in SPP is the need to source new load areas and demand for the existing units and proposed wind projects in the pipeline. HVDC lines are one of the solutions for this challenge. Of all the projects in the region, we feel that most promising is the Clean Line HVDC Project. The Plains & Eastern Clean Line is an approximately 700-mile DC transmission line that will deliver wind energy from the Oklahoma-Texas Panhandle region to utilities and customers in the Mid-South (MISO) and southeastern United States (TVA). The project also involves the construction of AC collector systems to collect and transport the energy generated by wind farms in the “wind alley” region of SPP. The project received DOE approval in early 2016 and construction commenced in late 2017 (Clean Line Energy Partners 2017b).

Clean Line HVDC Project – Case Study for SPP

For the SPP region, ICF focused on Plains & Eastern’s Clean Line HVDC Project as a detailed case study (DOE 2016, Clean Line Energy Partners 2017b). The project is expected to deliver nearly 4,000 MW of power from the Oklahoma-Texas Panhandle region to customers in Arkansas (MISO region), Tennessee (in TVA region), and other southwestern states using a 720-mile, 600-kV HCDC overhead line. Although the HVDC line is expected to be bi-directional, under normal operating conditions power will flow from the wind farms to the load centers in Arkansas and Tennessee. The project is also expected to stabilize regional grids by coordinating with neighboring control areas to change the direction of power flow rapidly if needed. The wind farms are expected to be directly connected to the Oklahoma converter station through a dedicated wind collector system. To summarize, the facilities associated with the project include converter stations located southeast of Guymon in Texas County, Oklahoma; northeast of Memphis in Shelby County, Tennessee; an intermediate converter station at Pope/Conway County in Arkansas; and an AC collector system for Oklahoma-Texas Panhandle region (DOE 2015a, Clean Line Energy Partners 2015). The project is expected to interconnect grids operated by SPP, MISO, and TVA.

In March 2016, DOE issued a Record of Decision approving the transmission project under Section 1222 of the Energy Policy Act, 2005 (DOE 2016, Plains and Eastern 2017). This is the first time a transmission project has been qualified under this authority that allows for participation of DOE in the implementation of the project (subject to certain conditions). The project also successfully cleared the applicable National Environmental Policy Act review in mid-2015 and has also secured the state regulatory approvals for operating as a public electric utility from Oklahoma and Tennessee but awaiting approvals from Arkansas (at the time of writing).

Figure 19. Overview of proposed clean line HVDC line



Source: Clean Line Energy Partners (2017b).

As discussed earlier in the report, the Clean Line Project accommodates the increasing demand for interregional transmission capacity to evacuate power from the “wind alley” region of Oklahoma-Texas Panhandle region to the load centers in the Mid-South and Southeast. In addition, the Panhandle region has some of the best wind resources in the country and has the potential to generate cost-effective wind power (under three cents per kilowatthour) (Clean Line Energy Partners 2015). There are recognized limitations to the existing regional transmission system to support the necessary wind energy development and deliver the low-cost power to the neighboring regions. Interregional HVDC lines like Clean Line can help to obviate such limitations and deliver cost-effective power to MISO and TVA regions. The project also facilitates the clean energy requirements of the TVA region by receiving nearly 3,500 MW of the line capacity. Finally, the need for increased west-east transfer capability was identified in several interregional studies like the Joint Coordinated System Plan involving MISO, SPP, PJM, and TVA and NREL’s Eastern Wind Integration and Transmission Study for facilitating wind integration in the region (Clean Line Energy Partners 2015).

Insights from Clean Line Case Study

Clean Line is expected to utilize a collector system that will in effect connect the wind generation resources directly to the client region, bypassing the host region. The line, which is expected to be more than 700 miles long, would show the advantage of HVDC when connecting supply resources to distant load centers in different balancing authorities.

A.2. Literature Survey on Applicability of HVDC for Renewable Integration

HVDC transmission is a topic of increasing interest for stakeholders in the power transmission industry. For this literature survey, ICF reviewed publicly available research studies, reports, industry articles, and journal articles to summarize the recent trends in HVDC technology and its deployment. These sources also provide insights about the benefits and challenges of HVDC implementation, and its applicability for facilitating greater renewable integration.

***Applications for High-Voltage Direct Current Transmission Technologies* – DOE (2013)**

This report discusses the applications of HVDC transmission technologies. The findings are based on a workshop organized by DOE in April 2013. This workshop was held to help participants develop a better understanding of HVDC transmission technologies and their application in the North American electric grid. The report identifies the benefits of implementing HVDC technologies such as: increased system stability, frequency regulation, forcing ordered power into an area, limiting fault currents, and providing black start capabilities. The report highlights the fact that HVDC technology can be applied for water crossings, asynchronous interconnections (back-to-back), bulk power transfers, and accessing offshore wind. The report suggests that technology hurdles may not be a significant issue for greater deployment, since losses associated with power electronic devices affect only the business proposition of using HVDC and controllability has improved (and continues to improve) tremendously. The report states that the biggest challenge for HVDC applications is the current regulatory landscape, since FERC Order No. 1000 (FERC 2011b) requires the allocation of costs of new transmission projects to beneficiaries, who are hard to identify.

***Improvement of Wind Energy Production through HVDC Systems* – Brenna et al. (2017)**

Published in January 2017 by Brenna et al. of Polytechnic University of Milan, this research study focuses on the implementation of HVDC systems on the Italian bulk power system. A model of the power system was developed to evaluate possible solutions to reduce wind curtailment, and a proposal for the construction of an HVDC line linking southern and northern Italy was studied.

The study models and simulates the impact of a long-distance HVDC connection between the country's northern and southern regions (about 800 km). The simulation shows that the introduction of the proposed HVDC line causes a significant drop of wind curtailment. The base case used in the model, representing the status of the grid, results in 119.8 GWh of overall annual curtailment. Once the proposed HVDC line (1000 MW capacity) is implemented, the overall annual curtailment drops to 31.9 GWh, a 73% decrease from the base case. Increasing the line capacity to 1,500 MW causes curtailment to drop to 25 GWh, a 79.1% decrease from the base case. The implementation of the HVDC line also affects the three main zones of the Italian power grid (SUD – South, NORD – North, SICI – Sicily). The over-generation occurring in SUD and SICI is more easily shifted to NORD, where the load is high enough to accommodate it. The annual hours in which the SICI-SUD lines are congested are reduced by 241 between the base case and the 1500 MW HVDC Case.

HVDC is also a better option since the long distance involved makes it more economical and more efficient compared to an AC connection. Despite long payback times involved with a DC investment, great substantial reductions in wind curtailments reductions make the implementation of an HVDC connection compelling. HVDC provide the capability to more easily and efficiently integrate renewable energy sources, which are bound to increase further in the coming years.

"HVDC on the Rise" – Hirsch, EPRI (2016)

The Electric Power Research Institute (EPRI) published this article in the January/February 2016 edition of the *EPRI Journal*. The issue focuses on the new opportunities and benefits of HVDC transmission implementation. Unlike HVAC transmission technology, HVDC travels through the entire cross-section of a conductor and needs fewer wires, enabling it to move energy over greater distances with less power loss. HVDC also provides controlled power flows, contributing to grid stability. As costs come down for DC transmission, the business case improves for even shorter distances.

According to the article, HVDC implementation also creates a few challenges, including the management of an HVDC link loss, the lack of familiarity with HVDC maintenance practices, the shorter lifetimes of HVDC assets compared to HVAC, and the expensive communication systems required for multi-terminal HVDC systems.

The article also notes that globally, the demand for HVDC is growing. This growth can be attributed to several factors, with the main one being the increasing renewable energy integration, which is well suited for HVDC. The need for increased system reliability is also a contributing factor, as HVDC can help reduce the spread of large-scale disturbances by providing a buffer between regions.

***Roadmap to the Supergrid Technologies* – Friends of the Supergrid (2012)**

Friends of the Supergrid is a group of energy companies with a mutual interest in promoting the policy and regulatory framework required to enable the creation of an HVDC Supergrid in Europe. The European Energy Forum defines a Supergrid as "a pan-European transmission network facilitating the integration of large-scale renewable energy and the balancing and transportation of electricity, with the aim of improving the European market."[21] In 2012, the group published a report regarding the drivers for European system expansion and the technologies available to aid this expansion, while presenting a possible roadmap along with various scenarios for developing the Supergrid.

The report provides a detailed description of HVDC cable types, such as mass-impregnated (MI) cables and extruded insulation cables (DC-XLPE). A breakdown of the factors influencing the decision between AC and DC transmission is also included. These factors include the transmission distance, the shunt reactive power compensation required for long cable links, the ROW requirements for each system, and the system stability provided by each system. According to the report, HVDC can provide damping to power oscillations because of its precise power flow control capability.

The gradual introduction of HVDC grids over the next 15 years is foreseen to be the key enabling technology to match renewable targets on the global markets. This is due to the benefits of HVDC implementation, which include: a DC line can transmit more than double the power at about half the losses compared to an AC line at a similar voltage level; HVDC lines, even overhead, have a considerably reduced footprint with consequent reduced consenting risk; and an HVDC in parallel to an AC system increases power transmission capacity and at the same time contributes to system stability.

[21] European Energy Forum. Friends of the Supergrid.

***HVDC Technology for Offshore Grids and a Supergrid in Europe* – Beerten, IEEE PES (2016)**

This presentation is from the IEEE Power & Energy Society (PES) General Meeting in 2016 by the University of Leuven and Energyville, a Belgian research institute. It focuses on the technological and regulatory challenges of HVDC technology implementation for offshore grids and the European Supergrid. A detailed comparison of AC and DC cables is provided, comparing attributes of the two system types, including controllability, investment costs, long-distance capabilities, and line losses.

The report discusses the present and future state of markets for HVDC technologies. It is noted that the worldwide HVDC market is in excess of $4 billion annually and rising, since HVDC grids are nowadays considered as the backbone for future transmission systems. The presentation highlights the challenges affecting HVDC grid implementation, such as power flow and DC voltage control, fault clearing capabilities, grid protection coordination, communication requirements, multi-vendor interoperability, and voltage level standardization. The lack of widespread HVDC implementation is attributed to the manufacturers, who are waiting for a robust demand from the market to speed up developments, and to the Transmission System Operators (TSOs), who are missing strong incentives to jointly develop interconnected HVDC grids under the current regulatory framework. The report suggests a continued focus on research and development (R&D) in the system operation and optimization fields, the development of interoperability guidelines and standards, and the conception of new control and operation guidelines by TSOs.

***Renewable Energy Integration in Power Grids* – IEA-ETSAP IRENA (2015)**

This technology brief, prepared by the International Energy Agency (IEA) Energy Technology Systems Analysis Programme (ETSAP)[22] and the International Renewable Energy Agency (IRENA),[23] provides insights on renewable energy integration in power grids. It includes a detailed grid interconnection section, noting that increased interconnection at a regional, national and international level would enable more flexibility in power transmission from regions with ample availability of renewables to other regions with high electricity demand. The benefits of higher interconnection capacity are discussed, which can be achieved through HVDC implementation. According to the brief, higher interconnection capacity allows for the optimal use of surplus generation, alleviates the problem of daily and seasonal peak demands, reduces the requirements for regulation reserves, enhances congestion management, and reduces the need for new generation capacity. It is also noted that HVDC transmission lines are highly efficient, although their implementation takes time and involves significant upfront investment.

"Future Cost-competitive Electricity Systems and Their Impact on US CO_2 Emissions" – MacDonald et al. (2016)

Published in the May 2016 edition of *Nature Climate Change*, this article provides an overview of future cost-competitive electricity systems and their impact on U.S. CO_2 emissions. It provides several reasons why HVDC should be implemented over HVAC, such as the long-distance transmission capability of HVDC, and the increased efficiency and lower cost compared to HVAC. It suggests that by using existing technologies, the U.S. electricity sector can substantially reduce its CO_2 emissions by 2030 without an increase in the LCOE, assuming learning curve cost reductions in wind and solar photovoltaics and the

[22] ETSAP is the longest running Technology Collaboration Programme of the International Energy Agency (IEA).
[23] IRENA is an intergovernmental organization founded in 2009. It promotes the adoption and sustainable use of renewable energy across its 150 member-states.

facilitation of a national HVDC transmission grid overlay. A national HVDC network is also proposed, asserting that a shift from a regionally divided system to a national one could save U.S. consumers an estimated $47.2 billion annually, which amounts to almost three times the cost of the HVDC transmission per year. This national power system would consist of a web of lines connecting 32 nodes, allowing power to flow between each region. The HVDC reduces the potential of whole electrical power system blackouts because the entire system does not need to operate at exactly the same frequency. The supplementary information document of the article includes costs for HVDC, estimating the transmission line cost at $701/MW-mile and the transformer station cost at $182K/MW. The cost is highly dependent on the length of the transmission lines.

***High-Voltage Direct Current Transmission Systems* – Torvik and Lockhart, Navigant Research (2013)**

This report includes a global market analysis of HVDC transmission systems. The report provides a market overview and notes that more recent innovations in power electronics complement and extend AC systems with reliable, energy efficient, and high power HVDC voltage conversion and power transmission. It refers to the Hudson Transmission Partners' (HTP) project in New York and New Jersey as an example of an HVDC project designed to creatively address regional transmission intertie requirements. Navigant estimates that the HVDC transmission market constitutes approximately 333 GW of new transmission capacity between 2013 and 2020.

The HVDC drivers are also discussed, and Navigant suggests that the growth in electricity demand, along with the asynchronous operability and efficiency of HVDC, will lead to an increase in HVDC implementation. Navigant forecasts that the global cumulative HVDC converter revenue will amount to $56.6 billion in 2020, citing a growth in VSC demand. VSC is a technology that can be used for submarine HVDC transmission and is estimated to amount to 19% of total new HVDC capacity between 2013 and 2020.

***Quadrennial Technology Review – An Assessment of Energy Technologies and Research Opportunities* – DOE (2015b)**

This report provides an assessment of emerging energy technologies and associated research opportunities and provides an in-depth look into transmission and distribution components (HVDC converters, VSCs, and MMCs) along with suggestions for HVDC circuit protection. The report recommends that the HVDC protection systems be enhanced to ensure system reliability. The issue is that while protection technologies (for example, breakers) are mature for HVAC, they are less established for HVDC systems. Material and design innovations are expected to drive down costs and increase power ratings, accelerating technology deployment. Multi-terminal networks require advanced methods for DC fault identification and mitigation, and since many HVDC system components are in isolated locations, advances in circuit technology will aid in system protection, maintenance, and restoration.

***ABB Review – Special Report: 60 Years of HVDC* – ABB (2014)**

ABB Inc. published this special market report on the state of HVDC technology evolution over the past 60 years, along with a future market outlook, insights on future HVDC technologies and their potential impact on the U.S. power grid. According to the report, HVDC transmission systems provide numerous benefits, including twin-cable installation, which neutralizes magnetic fields, and an enclosed converter station, which efficiently suppresses noise and has a smaller station footprint compared to HVAC. New HVDC technologies (HVDC Light) allow for new system applications, such as remote offshore applications, weak system interconnections, and long land cables. The report notes that as the demand for energy grows, so does the demand for reliable energy supply. The report pitches HVDC technology as capable of offering more intelligent and better-controlled grid networks. These networks will be a combination of AC and DC technologies, embedding HVDC transmission inside the AC grid and reinforcing the operation of the whole grid with the controllability, speed, and low losses provided by HVDC. The report opines that increasing sub-sea transmission projects have opened the door to the further expansion of the global power cable network. HVDC transmission is critical to build such global cable networks. New VSC technology is expected to simplify the job of connecting weak AC networks as well as making it easier to transfer power from offshore wind generators and other remote renewables. Since HVDC has the capability of connecting asynchronous AC networks, it can effectively be used in very long sub-sea cables that connect AC systems. As stated in the report, a key enabling product for HVDC is the new, lightweight polymer-insulated cable, which allows systems with higher transmission to be built. HVDC transmission capability has grown from 80 kV during the first iteration of HVDC Light, to a remarkable 320 kV in projects that are currently under construction. The theoretical limits of HVDC's core technologies have not yet been reached, meaning that HVDC still has great potential for growth and is set to become an even more dominant technology for bulk power transmission.

***Integrating Renewable Electricity on the Grid* – APS Physics (2010)**

This report on the integration of renewable electricity on the existing power grid provides ways HVDC implementation can help with renewable integration. The report notes that HVDC is favored for distances greater than a few hundred miles, for its lower electrical losses, and for lower cost. The report states that the mandated growth of nationwide wind and solar generation through RPSs to 20% for 2020 or 30% for 2030 of electricity supply changes the landscape for long-distance transmission. This is because such large fractions of renewable power often are not found within 100 miles of urban load centers and rooftop photovoltaics can alleviate some of the need for long-distance transmission, but often at a higher cost than wind or concentrating solar power.

The report also discusses HVDC transmission implementation options, proposing that underground superconducting DC transmission lines allow for the creation of a national renewable electricity transmission system. These lines operate at zero resistance, eliminating losses for any transmission length, and they carry much more current and power than conventional conductors. Without losses, there is no need to raise voltage and lower current to extreme levels.

Finally, the report provides the following recommendations for DOE, specific to HVDC technology: extend the DOE/OE High Temperature Superconductivity program for 10 years, with a focus on DC superconducting cables for long-distance transmission of renewable energy from source to market; and accelerate R&D on wide-band gap power electronics for DC conversion options and development of semiconductor-based circuit breakers operating at 200 kV and 50 kiloamps with microsecond response time.

***New England Wind Integration Study* – GE Energy, ISO-NE (2010)**

This report, prepared for ISO-NE by GE Energy, was commissioned to assess the operational effects of large-scale wind penetration in New England using statistical and simulation analysis of historical data.

The report notes that while wind power is becoming more widespread because of its emission-free electrical energy, fast construction speed, and long-term fuel-cost certainty, certain challenges must be addressed to achieve proper integration. These challenges include the variability of wind resources, the uncertainty with which the amount of power produced can be accurately forecasted, and the fact that many favorable sites for wind development are located far from load centers It also notes that significant transmission development is required, which adds complexity to the operations and planning of the system.

The report addresses the Scenario Analysis of Renewable Resource Development (Governors' Economic Study), which was published in 2009 by ISO-NE. It provides a comprehensive analysis for the integration of renewable resources over a long-term horizon. This analysis was conducted by studying the economic and environmental impacts for a set of scenario analyses that assumed the development of renewables in New England, the potential for significant wind development in New England and effective means to integrate this wind power into the grid.

The analysis contends that New England could potentially integrate wind resources to meet up to 24% of the region's total annual electricity needs in 2020 if the system includes transmission upgrades comparable to the configurations identified in the Governors' Economic Study (2009). The study assumed continued availability of existing supply-side and demand-side resources as cleared through the second Forward Capacity Auction (FCA), retention of the additional resources cleared in the second FCA, and increases in regulation and operating reserves as recommended in the study. The results suggest that while New England may benefit from an increase in wind generation during the winter period, the region will still need to have adequate capacity to serve summer peak demand. Under the current operating practices and market structures, the potential displacement of electric energy provided by existing resources raises concern for maintaining adequate capacity and a flexible resource mix. The expected increase of wind generation penetration will increase the regulation capacity requirement and the frequency of utilization. Even at the lowest penetration level, the study identified a need for an increase in capacity, mainly due to the error margin in short-term wind forecasting. These challenges are addressed by simulating the transmission overlay proposed in the Governors' Economic Study (2009), which includes a 450 kV HVDC overhead line with a transport capability of 1500 MW, connecting New Brunswick and Massachusetts. This added HVDC cable increases the import capability into ISO-NE to about 3000 MW, therefore when the wind production is higher than the expected penetration level of 20%, the energy would be displaced or curtailed (1.15% total curtailment at 20% penetration using the HVDC cable).

Table 5, below, summarizes the studies and reports discussed in this section.

Table 5. Summary of recent literature on HVDC and its application in solving renewable intermittency

Title[24]	Year	Publisher	Type	Scope	Key Findings
Applications for High-Voltage Direct Current Transmission Technologies	2013	United States Department of Energy	Proceedings Document	HVDC transmission technologies workshop	• HVDC is essential for accessing offshore wind and other remote renewables • Technology hurdles may not be significant issue to greater deployment

[24] See Section 5, References, of this report for details on these sources.

Title[24]	Year	Publisher	Type	Scope	Key Findings
					• Biggest challenge for HVDC projects are regulatory approvals
Integrating Renewable Electricity on the Grid	2010	APS Physics	Report	Renewable energy integration and related technology issues	• There are drawbacks to implementing HVDC transmission for renewable integration: single-point of origin and termination, expensive and technically challenging conversion by semiconductor power electronics between AC and DC, substantial ROW requirements can take a decade or more to gain regulatory approvals • Historically low investment in transmission in the United States might be one of the main reasons for the lack of HVDC projects • Research & Development efforts should be focused on wide band gap power electronics
Improvement of Wind Energy Production through HVDC Systems	2017	MDPI	Journal Article	Italian power system modeling and analysis	• Implementation of an 800-km long HVDC line could result in a 79.1% reduction in annual wind curtailment in Italy • Despite long payback times involved with DC investments, considerable wind curtailment reductions make a strong economic case for HVDC line • HVDC has the capability to more easily and efficiently integrate renewable energy sources, which are bound to increase further in the future
HVDC on the Rise	2016	EPRI	Journal Article	HVDC history and outlook	• HVDC implementation introduces numerous challenges such as: managing the loss of an HVDC link, expensive communication system requirements, lack of utility familiarity with HVDC maintenance practices, shorter asset lifetimes (compared to HVAC) • Main drivers behind HVDC demand include the integration of renewables, increased reliability that HVDC provides, and the capacity constraints of the current transmission grid • Two main technical challenges: Enabling HVDC technology to handle multiple terminals, and making devices from different vendors interoperable
Roadmap to the Supergrid Technologies	2012	Friends of the Supergrid	Report	Applications, network technologies, and scenarios	• The choice between AC and DC transmission may be influenced by: transmission distance, shunt reactive

Title[24]	Year	Publisher	Type	Scope	Key Findings
				for the development of the European Supergrid	power compensation, ROW requirements, and system stability • Having an HVDC system in parallel to an AC system increases power transmission capacity and at the same time contributes to system stability
HVDC Technology for Offshore Grids and a Supergrid in Europe	2016	IEE PES	General Meeting Presentation	Technological and regulatory challenges and a way forward for the Europen Supergrid	• Manufacturers are waiting for a robust demand from the market to speed up developments • TSOs are missing strong incentives to jointly develop interconnected HVDC grids under current regulatory framework • Emphasis needs to be put on R&D: Component ratings need to be increased and costs must be reduced; circuit breakers, which are essential for reliable system operation, need further development; first prototypes encouraging
Renewable Energy Integration in Power Grids	2015	IEA-ETSAP and IRENA	Technology Brief	Renewable energy integration analysis	• Increased interconnection at regional, national and international level would enable more flexibility in power transmission from regions with ample availability of renewables to other regions with high electricity demand • Higher interconnection capacity allows for the optimal use of surplus generation, alleviates the problem of daily and seasonal demand peaks and reduces the need for new generation capacity
Future Cost-competitive Electricity Systems and Their Impact on U.S. CO_2 Emissions	2016	Nature Climate Change	Journal Article	Impact of a national electricity system on U.S. carbon dioxide emissions	• A network of HVDC transmission lines helps to develop wind and solar resource potential in the country • HVDC is more efficient and cheaper than HVAC and can transmit electricity efficiently over long distances • Using existing technologies, the U.S. electricity sector can substantially reduce its CO_2 emissions by 2030 without an increase in the LCOE. U.S. consumers could save an estimated $47.2 billion annually with a national HVDC-linked bulk power system
High-Voltage Direct Current Transmission Systems	2013	Navigant Research	Research Report (Executive Summary)	HVDC Converters, Cables, Submarine Interconnecti ons, Multi-	• The HTP project in New York and New Jersey signifies the potential for HVDC to offer congestion relief • The HVDC transmission market is estimated to constitute approximately

Title[24]	Year	Publisher	Type	Scope	Key Findings
				terminal Grids, and Hybrid Breakers: Global Market Analysis and Forecasts	333 GW of new transmission capacity between 2013 and 2020 • Forecast: Global cumulative HVDC converter revenue will amount to $56.6 billion in 2020
Quadrennial Technology Review	2015	United States Department of Energy	Report	Energy Technologies and Research Opportunities Assessment	• HVDC Converters is a mature technology with broad deployment in transmission systems worldwide. Proven to be economical for transferring bulk power over long distances, undersea applications, isolating AC systems, and interconnecting asynchronous networks • VSCs provide more flexibility and simplicity in system designs, having inherent black start capabilities and multi-terminal configurations. However, there are still challenges with power ratings, efficiency, and cost
ABB Review – Special Report: 60 Years of HVDC	2014	ABB	Technical Journal	Impact of HVDC, Applications and Components	• HVDC technology offers more intelligent and better-controlled grid networks. These networks are a combination of both AC and DC, HVDC reinforcing the operation of the AC grid with increased controllability, speed, and lower losses • New converter technology (VSC) is expected to simplify the job of connecting weak AC networks, along with the capability of transferring power from offshore wind generators and other remote renewables to load pockets • The theoretical limits of HVDC have not been reached yet, therefore HVDC still has great potential for growth and is set to become an even more dominant technology for bulk power transmission

Title[24]	Year	Publisher	Type	Scope	Key Findings
New England Wind Integration Study (NEWIS)	2010	GE Energy	Report	New England Wind Integration, Impact analysis, Proposed overlays (HVDC) for mitigation	• The expected increase of wind generation penetration in New England will increase the regulation capacity requirement and the frequency of utilization; even at the lowest penetration level, there is a need for an increase in capacity • A 450 kV HVDC overhead line with a transport capability of 1500 MW is modeled, connecting New Brunswick and Massachusetts; this line increases the import capability into New England (ISO-NE) to about 3000 MW, allowing for greater displacement of energy and a reduction in curtailment

A.3. Literature Review on HVDC Project Costs

As a first step, ICF reviewed publicly available sources on HVDC project costs. The following table furnishes a list of sources that provide information about specific HVDC-related project costs, or studies estimating the cost of HVDC and influencing factors.

Table 6. Cost estimates of HVDC projects (based on literature review)

Project/Study Name	Year	Source[25]	Current Status	Key Takeaways
Plains & Eastern Clean Line	2017	Clean Line Energy Partners	In development	• Approximately 700-mile HVDC transmission line • Estimated project cost of $2.5 billion
Transmission Expansion Planning Tool for WECC	2014	WECC (Black & Veatch)	Completed	• 500kV HVDC substation base cost = $2,559,250 • 500kV HVDC converter station cost = $460,708,500 • 500kV HVDC bi-pole line base cost ($/mi) = $1,536,385
Cross Sound Cable	2006	Babcock & Brown Infrastructure	Completed	• Approximately 24-mile HVDC undersea cable • Estimated project cost of $120 million • The Cross Sound cable project was acquired in 2006 for $213 million
Offshore Wind Power Connection – HVDC Cost Analysis	2016	Imperial College London	Completed	• Cable cost per mile (range) = $288.38–$443.11 • Cost is dependent on type of VSC-HVDC cable with varying size, resistance, capacitance, and steady state current
Hudson Transmission Project	2013	Powerbridge	Completed	• Approximately 7.5-mile cable (3.5 underwater, 4 underground) • Estimated project cost of $850 million

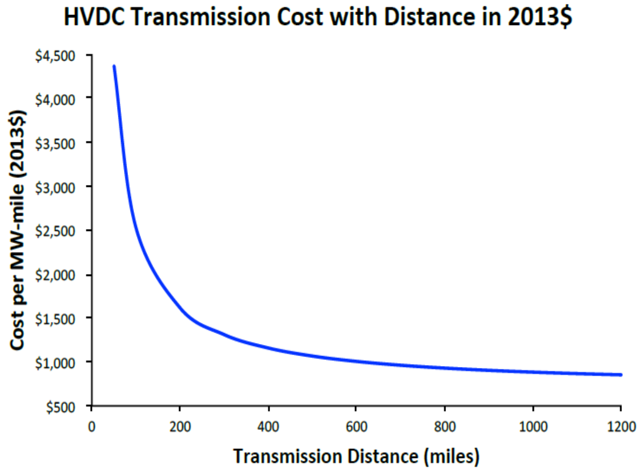
[25] See Section 5, References, of this report for details on these studies.

Project/Study Name	Year	Source[25]	Current Status	Key Takeaways
North-South Transmission Project	2012	Government of Alberta, Canada, Transmission Facilities Cost Monitoring Committee (TCFMC)	Completed	• Manitoba Project transmission line cost ($/mile)= $ 1,176,221 • Newfoundland Project transmission line cost ($/mile) = $ 1,189,166 • Alberta Project transmission line cost ($/mile) = $6,963,250
Labrador – Island Transmission Link	2017	Government of Newfoundland and Labrador, Canada	In Development	• Labrador-Island Link approximately 682-miles long • Cable and system upgrades estimated cost of $1.68 billion
Maritime Link	2017	Government of Newfoundland and Labrador, Canada	Completed	• Maritime Link approximately 111.6-miles long • Cable and system upgrades estimated cost of $961.91 million
Trans Bay Cable Project	2007, 2016	Babcock & Brown, FERC	Completed	• 53-mile HVDC submarine transmission • Approximate project cost (2007) = $440 million • Construction costs = $317 million • Non-construction costs (interconnection, development, mitigation, etc.) = $123 million • Transmission owner tariff increased from $131 million to $153 million
Electricity Transmission and Distribution Report	2014	ETSAP	Completed	• Long-distance transmission lines ($/MW-mi) = $890–$3,961 • Substation costs ($/MW) = $10,700–$24,000 • Intertie (AC-DC-AC) costs ($/MW) = $230,000 • Base grid interconnection costs ($/MW) = $110,000 (new generation and utility-scale storage technologies) • $100,000–$1,000,000 (remotely located wind and concentrating solar power technologies)

The table inset in Figure 20 summarizes the range of costs for HVDC lines based on estimates for the ten HVDC transmission projects listed in Table 6. The Hudson Transmission Project cost an approximate $113 million/mile, which is a clear outlier and does not represent most of the projects. The average cost for the rest of the projects amounts to $4.66 million/mile, with an average line length of ~approximately 262 miles. The highest estimated project cost is for the Maritime Link Project at $8.62 million/mile, which includes two sub-sea HVDC cables spanning approximately 105 miles across the Cabot Strait from Cape Ray (Newfoundland) to Cape Breton (Nova Scotia). The lowest project cost is for the Manitoba Bi-Pole III Transmission Line project at $1.17 million/mile. This is also the longest project, with a total cable length of 860 miles. Based on these project cost estimates, it is reasonable to assume that the project cost is not directly proportional to the cable line length in most cases. This assumption is further supported by

MacDonald et al. (2016),[26] in which an inverse correlation between transmission distance and cost per MW-mile for HVDC line is modeled. In Figure 20, we can see that the unit cost of HVDC projects drops rapidly with a distance up to 300 miles and then levels beyond that.

Figure 20. Unit cost estimates of HVDC technology



HVDC Projects – Cost Range (2017 $)	
Total Project Cost ($ million/mile)	1.17 to 8.62

Source: ICF review.

Source: MacDonald et al. (2016).

Table 7 provides the transmission and infrastructure cost estimates from NREL's JEDI model, WECC's Transmission Expansion Planning Tool, and ETSAP's Electricity Transmission and Distribution technology brief (2015). These estimates are provided for a 500 kV HVDC bi-pole line, assuming a flat terrain and a distance exceeding 100 miles. NREL JEDI and Black & Veatch (2014) provide similar transmission cost estimates ($1.44 million/mile and $1.53 million/mile), while ETSAP (2015) provides a transmission cost that is 2 to 2.5 times higher ($3.60 million/mile).

Total Infrastructure cost is assumed to include the cost of constructing two converter stations (one at each endpoint) and any additional transformers, shunt reactors, and series compensation required for the reliable operation of the transmission system. NREL estimates that cost to be around $734 million, including labor costs. Black & Veatch (2014) and ETSAP (2015) provide estimates significantly higher than NREL (Black & Veatch at $960 million and ETSAP at $1.182 billion). Assuming a 262-mile line, the calculated total cost-per-mile amounts to $4.24 million/mile for NREL, $5.19 million/mile for Black & Veatch, and $8.11 million/mile for ETSAP. All three estimates are within the project cost range (Table 6), calculated by comparing the total project cost and transmission distance of ten recent HVDC projects in North America.

Table 7. Transmission and infrastructure cost estimates (for a hypothetical HVDC line)

	NREL JEDI 2017	WECC Transmission Expansion Planning Tool[27]	ETSAP Electricity Transmission and Distribution
Transmission Line Cost ($ million /mile)	$1.44	$1.53	$3.60
Infrastructure Cost ($ million)	$734	$960	$1182
Calculated Total Cost ($ million/mile)	$4.24	$5.19	$8.11

[27] Costs extracted from WECC Transmission Expansion Planning Tool, prepared by Black & Veatch. Costs have been adjusted from 2014$ values to 2017$ using ICF's assumption of 2.1% inflation per year. These costs assume an HVDC 500-kV bi-pole line exceeding 10 miles in length. The listed costs are baseline costs, meaning that additional cost multipliers have not been applied.

A.4. List of Existing and Proposed HVDC Projects in the United States

Table 8. Existing HVDC projects

Project Name	Year of Commission	Power Ratings	Voltage Ratings	Line Length (mile)	Conversion Technology	Application
Pacific Intertie	1970; upgrades in 2020 (planned)	3,800 MW (Celilo) / 3,220 MW (Sylmar)	± 500 kV	845	LCC (thyristor)	Remote Generator Interconnection
Intermountain	1986; upgrade in 2010	2,400 MW	± 500 kV	488	LCC (thyristor)	Remote Generator Interconnection
Quebec–New England	1990; upgrade in 2016	2,000 MW	± 450 kV	920	Multi-terminal LCC (thyristor)	Remote Generator Interconnection
Square Butte	1977; upgrade in 2004	500 MW	± 250 kV	465	LCC (thyristor)	Remote Generator Interconnection
CU	1979; upgrades in 2004 and 2019 (planned)	1,000 MW	± 400 kV	427	LCC (thyristor)	Remote Generator Interconnection
Trans Bay Cable	2010	400 MW	± 200 kV	53	VSC (IGBT) MMC	Congestion Relief (merchant project)
Neptune Cable	2007	660 MW	500 kV	65	LCC (thyristor)	Congestion Relief (merchant project)
Cross Sound Cable	2003	330 MW	± 150 kV	24	VSC (IGBT)	Congestion Relief (merchant project)
Hudson Transmission Partners	2013	660 MW	345 kV	7.5	LCC (thyristor)	Congestion Relief (merchant project)
Oklaunion	1984; upgrade in 2014	220 MW	31 kV	Back-to-back	LCC	Grid Interconnection (ERCOT and EI)
ERCOT East DC-Tie (Welsh)	1995	600 MW	179 kV	Back-to-back	LCC	Grid Interconnection (ERCOT and EI)
Eagle Pass	2000	36 MW	± 15.9 kV	Back-to-back	VSC (IGT)	Grid Interconnection (ERCOT and Mexico)
Railroad	2007	150 MW	± 21 kV	Back-to-back	LCC	Grid Interconnection (ERCOT and Mexico)
Blackwater	1984; upgrade in 2009	200 MW	57 kV	Back-to-back	LCC	Grid Interconnection (ERCOT and WECC)
David A Hamel	1977	100 MW	50 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)
Eddy County	1983	200 MW	82 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)

Project Name	Year of Commission	Power Ratings	Voltage Ratings	Line Length (mile)	Conversion Technology	Application
Miles City	1985	200 MW	82 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)
Virginia Smith	1988	200 MW	50 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)
McNeill	1989	150 MW	42 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)
Rapid City	2003	200 MW	± 13 kV	Back-to-back	CCC	Grid Interconnection (EI and WECC)
Lamar	2005	210 MW	± 63.6 kV	Back-to-back	LCC	Grid Interconnection (EI and WECC)

Table 9. Proposed HVDC projects in the United States (selected)

Project Name	Year of Commission	Power Ratings	Voltage Ratings	Line Length (mile)	Conversion Technology	Application
Plains and Eastern's Clean Line	2020 (expected)	4,000 MW	± 600 kV	720		Renewable Resources Integration (merchant)
TransWest Express	2020 (expected)	3,000 MW	± 600 kV	730		Connect Renewable Energy
Champlain Hudson Power Express	2021 (expected)	1,000 MW	320 kV	335		Congestion Relief (merchant project)
Zephyr Power Transmission	Mid-2020s (expected)	3,000	500 kV	500–850		Renewable Resources Integration (merchant)
Maine Power Express	2022 (expected)	1,040 MW	± 320 kV	303		Renewable Resources Integration (merchant)
New England Clean Power Link	2020 (expected)	1,000 MW	300-320 kV	150		Renewable Resources Integration (merchant)
Southern Cross	2021 (expected)	2,000 MW	± 500 kV	400		Renewable Resources Integration (merchant)
Lake Erie Connector	2020 (expected)	1,000 MW	± 320 kV	72		Merchant
Centennial West Clean Line	Mid-2020s (expected)	3,500 MW	600 kV	900		Renewable Resources

Project Name	Year of Commission	Power Ratings	Voltage Ratings	Line Length (mile)	Conversion Technology	Application
						Integration (merchant)
Grain Belt Express Clean Line	2021 (expected)	4,000 MW	± 600 kV	780		Renewable Resources Integration (merchant)
Tres Amigas Interconnection	200 MW			Back-to-back	VSC	Grid Interconnection (EI – ERCOT – WECC)
Nogales Interconnection	150 MW planned for 2019; remainder TBD	300 MW		Back-to-back		Grid Interconnection (WECC and Mexico)

A.5. Glossary

Capacitor-commutated converter (CCC): A type of converter used in HVDC systems, which has series capacitors, inserted into the AC line connections, either on the primary or secondary side of the converter transformer. The series capacitors partially offset the commutating inductance of the converter and help to reduce fault currents. This also allows a smaller extinction angle to be used with a converter/inverter, reducing the need for reactive power support. CCCs have remained only a niche application because of the advent of voltage-source converters (VSC), which eliminate the need for an extinction (turn-off) time.

Converter: An electrical or electro-mechanical device for converting electrical energy from one form to another, such as converting between AC and DC, changing the voltage or frequency, or a combination. An HVDC converter converts electric power from high-voltage AC to high-voltage DC current, or vice versa.

Commutation: The process of transferring current from one connection to another within an electric circuit. Depending on the application, commutation is achieved either by mechanical switching or by electronic switching. The equivalent of mechanical commutation occurs in solid-state converter circuits such as those used for rectifying AC to DC or inverting DC to AC.

Circuit breaker: An automatically operated electrical switch designed to protect an electrical circuit from damage caused by excess current, typically resulting from an overload or short circuit. Its basic function is to interrupt current flow after a fault is detected. A circuit breaker can be reset (either manually or automatically) to resume normal operation. Circuit breakers vary from small devices that protect low-current circuits or individual household appliances, to large switchgear designed to protect high-voltage circuits.

Harmonics: Deviation of current and voltage in an electrical system from sinusoidal waveforms. Harmonic currents are caused by non-linear loads (loads that do not have the same waveform as the supply voltage) connected to the system. Harmonic frequencies are a common cause of power quality problems.

HVDC: A high-voltage, direct current system uses direct current for the bulk transmission of electric power, in contrast with more common AC systems. The advantages of HVDC include lower electrical losses for long-distance transmission compared to AC lines, and the ability to transmit power between asynchronous DC systems.

Interties: An interconnection permitting power flow between two or more grid asynchronous grid networks.

Line-commutated converters (LCC): A converter system in which the conversion process relies on the line voltage of the AC system to which the converter is connected in order to effect the commutation from one switching device to its neighbor. LCCs use switching devices that are either uncontrolled (such as diodes) or that can only be turned on (not off) by control action, such as thyristors. In practice, all LCC HVDC systems use either grid-controlled mercury-arc valves (until the 1970s) or thyristors (to the present day). Most of the HVDC systems in operation today are based on LCCs.

Mercury-arc valves: A type of electrical rectifier used for converting high-voltage AC into DC. They were the primary method of high power rectification before the advent of semiconductor rectifiers, such as diodes, thyristors, and gate turn-off thyristors (GTOs) in the 1970s. These solid-state rectifiers have since completely replaced mercury-arc rectifiers thanks to their higher reliability, lower cost and maintenance, and lower environmental risk.

Skin effect: The tendency of an alternating electric current to become distributed within a conductor such that the current density is largest near the surface of the conductor, and decreases with greater depths in the conductor. The electric current flows mainly at the "skin" of the conductor, between the outer surface and a level called the skin depth. The skin effect causes the effective resistance of the conductor to increase at higher frequencies where the skin depth is smaller, thus reducing the effective cross-section of the conductor.

Real power: The portion of power that, averaged over a complete cycle of the AC waveform, results in net transfer of energy in one direction, also known as active power. Measured in Watts.

Reactive power: The portion of dissipated power resulting from inductive and capacitive loads, measured in volt-amperes reactive. This power cannot do useful work at the load.

RMS Voltage: The root-mean square (RMS) mathematically represents the square root of the average squared value of a quantity over an interval. This is commonly applied to AC voltage, which is continually changing between zero, the positive peak, and the negative peak. RMS voltage represents the effective value of a varying voltage or current. It is the equivalent steady DC (constant) value, which gives the same effect.

Transformer: An electrical device that transfers electrical energy between two or more circuits through electromagnetic induction. Transformers are used to step-up or step-down voltage in AC networks.

Thyristor valves: A thyristor, also known as a semiconductor-controlled rectifier, is a solid-state and four-layered semiconductor used in electronic devices and equipment to control electrical power or current output through a phase angle control technique. Thyristor cells (referred to as valves) are a common technology used in modern HVDC convertor stations, and are typically found in line-commutated converters (LCCs). Thyristor valves have a breakdown voltage of a few kilovolts each. For a typical HVDC converter station, thyristor converters are constructed using large number of thyristors connected in series.

Thury system: The first commercial system for high-voltage DC transmission developed by Rene Thury and first put into service in Italy in 1889 with additional systems installed internationally over the next several decades. The Thury System used generators in series to attain high voltages. While AC transmission systems became dominant, Thury systems continued to operate until the 1930s.

Voltage-source converter (VSC): A technology used in HVDC converter stations. VSCs make use of semiconductor devices such as insulated-gate bipolar transistors (IGBTs) and gate turn-off thyristors (GTOs), which can both turn off and turn on (whereas thyristor valves used in traditional LCCs can only turn on). The VSC converter consists of two-level or multilevel converters, phase-reactors, and AC filters. Each single valve element is built up with a number of series-connected IGBTs together with associated power electronics devices. VSC technology has been used increasingly in HVDC projects in recent years.